SOUTHWEST RESEARCH INSTITUTE
P. O. Drawer 28510
San Antonio, Texas 78228-0510

# EVALUATION OF HURRICANE-INDUCED DAMAGE TO OFFSHORE PIPELINES

By

J. S. Mandke, Ph.D.
Y.-T. Wu, Ph.D.
R. S. Marlow, P. E.

FINAL REPORT
Contract No. 14-35-0001-30748
SwRI Project 07-6159

Prepared For

Minerals Management Service
Technology Assessment and Research Branch
381 Elden Street, MS 4700
Herndon, Virginia 22070-4817

March 1995

Approved:

Edward M. Briggs, Director
Marine Technology Department

## Table of Contents


| | | | Page |
|---|---|---|---|
| 1.0 | INTRODUCTION | | 1 |
| 2.0 | INDUSTRY SURVEY | | 4 |
| | 2.1 | Design Wave Height | 4 |
| | 2.2 | Pipeline Shut Down Procedures | 4 |
| | 2.3 | Pipeline Inspection | 5 |
| | 2.4 | Small Size Riser Damage | 5 |
| | 2.5 | Mechanical Connectors | 5 |
| | 2.6 | Buried Pipelines | 5 |
| | 2.7 | Excessive Pipeline Failures | 6 |
| | 2.8 | Pipeline Survival | 6 |
| | 2.9 | Pipeline Data | 6 |
| 3.0 | FAILURE DATA ANALYSIS | | 8 |
| | 3.1 | Hurricane Andrew Data | 12 |
| | | 3.1.1 Pipe Size | 12 |
| | | 3.1.2 Failure Cause | 12 |
| | | 3.1.3 Damage Location | 20 |
| | | 3.1.4 Failures Grouped by Product | 20 |
| | | 3.1.5 Age of Damaged Lines | 25 |
| | | 3.1.6 Failures by Water Depth | 27 |
| | | 3.1.7 Pollution From Damaged Lines | 27 |
| | 3.2 | Pre-Andrew Storm Failure Data | 27 |
| 4.0 | PIPELINE DESIGN PROCEDURES | | 41 |
| | 4.1 | Riser Design | 41 |
| | 4.2 | On-Bottom Stability | 42 |
| | 4.3 | Mud Slides | 43 |
| | 4.4 | Soil Liquefaction | 43 |
| | 4.5 | Buried Pipelines | 44 |
| 5.0 | POLLUTION MITIGATION | | 46 |
| | 5.1 | Design Procedures | 46 |
| | 5.2 | Operating Procedures | 47 |
| | 5.3 | Inspection and Leak Detection | 47 |
| 6.0 | ON-BOTTOM PIPELINE STABILITY RELIABILITY ANALYSIS | | 49 |
| | 6.1 | Concepts in Risk-Based Pipeline Design | 49 |
| | 6.2 | Time-Variant Reliability Analysis | 50 |
| | 6.3 | Vector-Outcrossing Reliability Analysis | 51 |
| | 6.4 | On-Bottom Stability Reliability Analysis Example | 52 |
| | | 6.4.1 Limit-State Surface | 53 |
| | | 6.4.2 Pipeline Design Parameters | 53 |

## List of Figures


| | | Page |
|---|---|---|
| Figure 1. | Path of Hurricane Andrew | 2 |
| Figure 2. | Pipeline Failures During 1983-92 | 9 |
| Figure 3. | Pipeline Failures During 1973-82 | 10 |
| Figure 4. | No. of Failures Per Pipe Size | 13 |
| Figure 5. | Failures Per Pipe Size Group | 14 |
| Figure 6. | No. of Failures Per Pipe Size (w/o Platform Damage) | 15 |
| Figure 7. | Failures Per Pipe Size Group (w/o Platform Damage) | 16 |
| Figure 8. | Percent Failure Type Per Pipe Size Group | 21 |
| Figure 9. | No. of Failures by Damage Location | 23 |
| Figure 10. | No. of Damaged Pipelines by Product (w/o Platform Damage) | 26 |
| Figure 11. | Percent Failures by Age Group (w/o Platform Damage) | 29 |
| Figure 12. | Percent Failures by Water Depth | 32 |
| Figure 13. | Failures Per Pipe Size Group (1967-91) | 35 |
| Figure 14. | Percent Failures Per Pipe Size Group (1967-91) | 36 |
| Figure 15. | Damaged Lines by Product (1967-91) | 39 |
| Figure 16. | Expected Number of Crossings Versus Concrete Coating Thickness for Two Cases | 58 |

# List of Tables


| | | Page |
|---|---|---|
| Table 1. | Storm Related Pipeline Failures, 1967-92 | 11 |
| Table 2. | Pipeline Failures During Various Hurricanes | 11 |
| Table 3a. | Damaged Line Lengths by Pipe Size | 17 |
| Table 3b. | Damaged Line Lengths by Pipe Size Group | 17 |
| Table 4. | Pipeline Damage Cause | 18 |
| Table 5. | Pipeline Damage Location (w/o Platform Damage) | 22 |
| Table 6. | Damaged Pipelines Grouped by Product | 24 |
| Table 7. | Damaged Pipelines by Product (w/o Platform Damage) | 25 |
| Table 8. | Age of Failed Pipelines (w/o Platform Collapse) | 28 |
| Table 9. | Pipeline Damage by Water Depth (feet) | 30 |
| Table 10. | Pipeline Damage by Water Depth (w/o Platform Damage) | 31 |
| Table 11. | Pipeline Failures Due to Storms and Mud Slides (1967-91) | 34 |
| Table 12. | Pipeline Damage Location (1967-91) | 37 |
| Table 13. | Damaged Pipelines by Product (1967-91) | 38 |
| Table 14. | Pollution From Pipelines Damaged by Storms | 40 |
| Table 15. | Computed Expected Number of Crossings | 57 |

## 1.0 INTRODUCTION

On August 25, 1992, Hurricane Andrew passed through the Gulf of Mexico (GOM) crossing an area with a large number of oil and gas producing fields in the Outer Continental Shelf (OCS). Hurricane Andrew was a category-4 level storm sustaining winds up to 140 miles per hour with gusts reaching 160 miles per hour and significant wave heights estimated to be at 35-40 feet. Typically, for a hurricane in the GOM, the highest wind speeds are experienced by the facilities 50 miles to the right and 35 miles to the left of the path of the storm eye. Figure 1 (from Ref. 1) shows the path of the eye of the Hurricane Andrew tracked about 5-10 miles southwest of South Pelto block along with the corridor which was affected by the storm. Other areas severely affected by the storm included South Timbaliar, Ewing Bank, Ship Shoal and Eugene Island. Close to 2000 oil and gas producing facilities in this area were exposed to severe hurricane winds. The damage to these facilities was quite severe and surpassed significantly the damage from any of the previous hurricanes in the GOM. About 36 major platforms and 145 satellite well jackets and caissons were damaged.

In addition, over 480 pipelines and flow lines were damaged. Four jack-up rigs tilted off of their original positions and six semi-submersible drilling rigs drifted from their locations. In view of this enormous damage, the Minerals Management Service (MMS) initiated several studies to investigate various issues related to storm impact on offshore production facilities. Pipeline operators shown in the shaded area of Figure 1 were required by MMS to survey these lines and risers. Southwest Research Institute (SwRI) was given a contract to study offshore pipeline damage that resulted from Hurricane Andrew. The results of SwRI's are presented here.

The scope of the study included damaged segments of oil and gas transmission lines and intra-field flow lines which included the production lines and the service lines for gas supply, water, well test, gas injection, etc. Throughout this report, the term "pipeline" has been generically used to include all types of lines listed above.

Most of the pipelines and platforms installed in the Gulf of Mexico after the early 1970's have been designed for 100-year storm conditions. Several structures installed earlier were designed on the basis of 25-year storm criteria. While most of the older structures did not perform as well as the ones installed after 1970, several of the pipelines were damaged during Hurricane Andrew in spite of their 100-year storm design criteria. Andrew's path was slightly to the west of the Mississippi delta region. Consequently, there were only a few mud slides that resulted from Hurricane Andrew and only a small number of lines were damaged due to mud slides. Several of the unattended drilling vessels drifted during the storm and their anchors and anchor lines damaged some of the pipelines.

Generally, hurricane-induced damage to pipelines can be attributed to one or more of the following failure scenarios:

a) Excessive pipeline movement on the seabed due to loss of on-bottom stability under the extreme hydrodynamic loading during a storm.

b) Excessive pipeline movement due to the impact force from a mud slide.

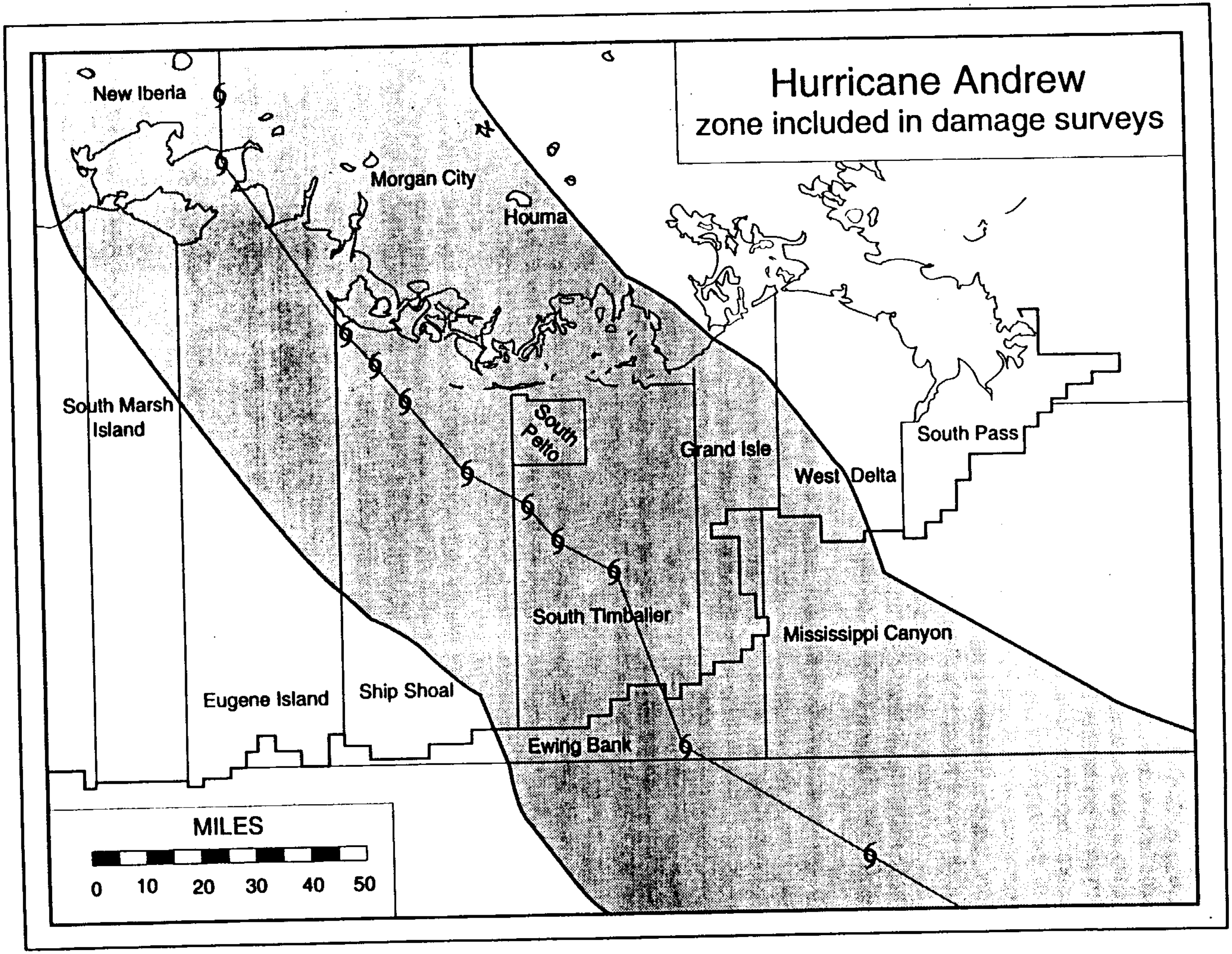



Figure 1. Path of Hurricane Andrew

c) Damage to the platform riser or the riser-to-pipeline tie-in due to excessive movement of the pipeline on the seabed.

d) Damage to the platform riser either due to an excessive platform movement during the storm or due to an inadequate design of the riser support clamps.

e) Damage from anchors and anchor lines of unattended drilling and construction vessels that drift off-site during the storm.

The objectives of this study included: an evaluation of the available data on pipeline failures due to Hurricane Andrew, identifying the probable reasons for the large number of failures, evaluation of current pipeline design and operating procedures, and to make recommendations to the industry that will minimize the damage from future hurricanes.

The majority of pipeline failures due to Hurricane Andrew occurred among small sized pipelines with nominal outside diameters of six inches or less and in water depths of less than 70-80 feet. This is consistent with the results of previous failure analysis reported by Mandke [2]. Department of Transportation (DOT) and the MMS regulations require that all pipelines and flow lines in water depths less than 200 feet be buried to a depth of three feet below the seabed. A pipeline buried at this level is expected to be protected from hydrodynamic loading under severe storm conditions. The question naturally arises as to why such a large number of pipelines failed during Hurricane Andrew. Although Andrew was a category-4 storm, there have been storms of this level that have crossed the GOM in the past. They include: Hurricane Camille in 1969 (category-5), Audrey in 1957 (category-4), and Carla in 1961 (category-4). Fortunately, during these past storms the GOM was not much developed and the resulting damage was minimal. A future storm of category-4 and above which crosses a region of the Gulf that is densely populated with offshore production structures has the potential to inflict a similar level of damage as Andrew. It is therefore imperative that the probable reasons for the excessive pipeline damage due to Hurricane Andrew be identified so that damage levels can be minimized in the future. The results provided in this report give some answers that will be helpful to the industry.

The study included a survey of offshore operators to obtain information regarding the currently followed pipeline operating procedures and their experience relative to Hurricane Andrew. The extensive pipeline failure data maintained by MMS [3] was analyzed and evaluated. Current design procedures for pipeline protection during a storm and methods for minimizing pollution from ruptured pipelines were reviewed. Finally, a reliability-based model was developed to analyze pipeline safety during a storm with respect to on-bottom stability. This probabilistic method of analysis addresses the various uncertainties in the design data and loads, and demonstrates how their variation impacts pipeline safety. Recommendations are made for minimizing the potential damage to pipelines and platform risers during future hurricanes.

## 2.0 INDUSTRY SURVEY

A survey of offshore operators who experienced pipeline failures due to Hurricane Andrew was done through the MMS's New Orleans Office. This was conducted primarily through a questionnaire soliciting information on issues such as the pipeline design criteria, shut-in procedures, post-storm inspection, probable causes of failures, etc. A sample questionnaire is included in Appendix A.

Overall, about 28 operators experienced pipeline damage during Hurricane Andrew, all of which were contacted for the survey. Fourteen companies responded to the questionnaire. The survey questionnaire also included a list of the pipeline segments belonging to the respective operating companies that were recorded by MMS as damaged. The majority of operators concurred with the MMS data. Four operators made minor corrections to this data. One operator reported 13 additional segments that were found damaged due to Andrew and subsequently repaired. A second operator reported 14 new damaged segments which were subsequently repaired. Eight of these segments had modifications following replacement of a damaged platform and six segments required only reinstallation of concrete mats to cover the pipeline. Since sufficient details on these additional segments were not available, this information was not added to the data base. Significant information obtained through the survey responses is summarized as follows.

### 2.1 Design Wave Height

Pipelines that are left on the seabed are designed for on-bottom stability during a 100-year storm. Also, the platform riser is designed to withstand the platform motion during a 100-year storm and the associated hydrodynamic loading. Companies were asked about the design criteria used for pipelines installed before 1970 versus those installed after 1970. Although the specific extreme storm criteria used for the pipeline design depends on the line location and the water depth along the pipeline route, general information was sought to determine the overall design practice. Most companies (11) could not provide information on the design wave and current used for pipelines installed prior to 1970. Three companies made general reference to the available oceanographic data or the prevailing version of API RP 2A [4] for the recommended design wave. For lines installed after 1970, six companies said that they use the design wave recommended in API RP 2A. One company said that for Ship Shoal 139 and South Timbalier 72, they use a wave height of 50.4 feet and 15.8 second period in 64 feet of water depth applicable . These values are very close to the maximum wave height recommended in the twentieth edition of API RP 2A.

### 2.2 Pipeline Shut Down Procedures

Most pipelines are shut-in prior to a storm's arrival using either manually operated or automatically operated isolation valves. The intra-field flow lines are shut in at the wellhead. Only one operator stated that some of their automated production lines continued to operate during the storm. Most gas pipeline operators reported leaving lines under full operating pressure. Five operators stated they leave the isolated oil lines at reduced pressure. None of the operators bleed down the lines prior to vacating the platform. No specific information was provided on long distance, large diameter oil transmission lines.

## 2.3 Pipeline Inspection

Companies were asked what pipeline inspection procedures were followed after the storm event and prior to bringing the lines back to full production levels. Eleven operators stated that they performed inspections either from the air or during supply boat trips. Significant pipeline damage was identified visually by gas bubbles or a slick over the ruptured line. Three operators stated that they performed fly-over inspections only if a leak was suspected. Diver inspection close to platforms is performed only if riser damage or a leak is evident. ROV inspection is not a commonly followed method in the GOM. Only two operators made reference to potential use of ROV inspection on as-needed basis.

## 2.4 Small Size Riser Damage

A very large portion of the pipeline risers damaged during Hurricane Andrew were of small size (2" to 6" diameter). Operators were asked their opinion regarding the extensive damage to small size risers. Seven operators had no opinion on this subject or did not experience damage to small size risers. The remaining seven companies attributed riser failures to inadequate design, improper clamp size or clamp spacing, or to movement of the pipeline on the seabed. One operator stated that the small size lines were installed as self-burying lines. Since there is significant bottom sediment movement in this area, it is quite likely that the pipelines may have been exposed and displaced significantly during the storm, resulting in subsequent riser damage.

## 2.5 Mechanical Connectors

During the last fifteen years, use of break-away safety joints, flexible jumper pipes, and other mechanical connectors at the pipeline to platform riser tie-in has increased significantly. These devices are used to protect the riser and the pipeline in areas prone to mud slides. Although there were very few mud slides during Andrew, operators were asked about the perceived effectiveness of these devices in protecting risers and pipelines. Ten operators had no experience with these devices or did not experience mud slides on their lines. For one operator, the break-away joint on an 18" size line did separate at the riser tie-in as it was designed to do. It effectively protected both the pipeline and the riser from damage. Another operator stated that they did not experience any mud slides but were in favor of using break-away connectors to limit the release of hydrocarbons. One operator reported good success with the mechanical connectors, but also reported that the break-away connectors has not been beneficial in preventing pipeline damage. For this operator, the use of flexible pipe jumpers has been beneficial in the mud slide area. One operator felt that break-away joints can release gas under the platform and can be a greater hazard to platform facilities than if they were not used.

## 2.6 Buried Pipelines

Pipelines buried below the seabed level are expected to be protected during a storm from damage due to excessive hydrodynamic loading. However, in the area affected by Hurricane Andrew, the bottom soil consists of soft sediment and is known to move during a storm. In addition, several lines in this area were installed for self-burial. Operators were asked about their experience with the performance of the buried pipelines, i.e. whether the lines remained in the trench as-built, lost backfill and protective cover, or moved out of trench.

Eleven operators reported that their pipelines remained buried, as-originally installed, during the storm. Of these, two reported some scouring and loss of cover for lines in shallow water depths (< 50 feet). Two operators had either no information or did not have buried lines in the path of Andrew. In addition, one operator reported that small size lines (3" to 4" diameter) which were installed for self-burial in the Ship Shoal area were unburied and moved significantly. For this operator, the lines in the Bay Marchand area remained in the trench with no apparent loss of backfill and the lines in the South Timbalier and South Pass area remained in the trench, as originally installed, with some loss of backfill near the platforms.

## 2.7 Excessive Pipeline Failures

Compared with the previous hurricanes in the GOM, Hurricane Andrew resulted in damage to a very large number of pipelines, flow lines and risers. This statement is valid even after excluding the damage to pipelines and risers that were associated with failed platforms, jackets and caissons. Operators were asked if they have any opinion regarding why such a large number of pipelines failed during Hurricane Andrew.

Seven operators had no comment regarding the extensive pipeline damage due to Andrew. Two operators attributed the failures to insufficient burial of pipelines. The remaining five operators attributed the failures to severity of the storm, the presence of a large number of flow lines in the path of the storm, and to the old age of the lines which may have been designed to 25-year wave criteria.

## 2.8 Pipeline Survival

Several of the pipelines and risers in Andrew's path survived without any damage. Operators were asked to identify any unique features associated with these undamaged lines.

Nine operators had no opinion regarding causes for the survival of these lines. Three operators attributed the lack of pipeline damage to proper burial at three feet below the seabed. Two operators attributed appropriate riser support for their survival. One operator stated that large diameter lines were not damaged and that the use of higher wall thickness on some of the risers also seemed to be helpful in reducing the damage. Another operator stated that the use of break-away connectors helped in protecting lines impacted by mud slides.

## 2.9 Pipeline Data

Operators were asked about the availability of engineering data for pipelines that failed or survived Hurricane Andrew. These data would have been helpful in determining the probable causes of survival or failure. However, the majority of the operators were not able to supply these data. This was partly due to lines being old or to change in ownership of the lines. Only three operators indicated availability of the requested pipeline data. These data were not obtained by SwRI primarily due to schedule constraints of the project. Based on information contained in permit applications, data on some selected lines were provided by the MMS' New Orleans Office. These data were not sufficiently complete to identify failure causes.

In summary, the survey collected the industry's input regarding pipeline damage due to Andrew. Information was provided on important issues such as pipeline and flow line shut in procedures, post-storm pipeline inspection practices, and probable reasons for the extensive damage to pipelines. On some issues, such as the performance of buried lines or the break-away connectors, survey responses were not entirely compatible with the information available in the MMS database on pipeline failures. For example, several lines lost anodes, protective cover, or were unburied during the storm and yet, most of the operators stated that the lines remained in the trench without loss of cover. Such inconsistencies may have been primarily due to the specific experiences of the individual operators who responded to the survey.

## 3.0 FAILURE DATA ANALYSIS

MMS maintains a historical database [3] on all pipeline failures that have occurred in the GOM since 1967. Recent data is available on computer while older data is available in hard copy. The computer database is being continuously updated by MMS to include new accident records, and to transfer old data from the hard copy. As such, the results presented here are based on the status of the database received during this study and do not reflect any subsequent updates or corrections made to this database by MMS. Each operator is required to report to MMS all pertinent information after a pipeline damage is noticed. However, such information (especially in the older records), is sometimes brief or nebulous. For the purpose of this study, those records have been interpreted as considered appropriate. For the reasons stated above, the results presented here differ in some instances from those presented by Daniels [1] and Williamson [5] on Hurricane Andrew. However, these differences do not change the conclusions of the study.

The results presented here are based on an analysis of 485 reported failures in the MMS database. Some records were not pertinent to this analysis and were ignored; for example, those resulting from replacement of damaged structures. Although the database includes pipeline segments which are under Department of Interior (DOI), MMS or the Department of Transportation (DOT) jurisdictions, no distinction has been made between the DOI and the DOT segments during the analysis. In addition to Hurricane Andrew related failures, data from all the previous storm related failures have been analyzed.

The failure database lists the pipeline accidents by pipe size, pipeline operator, transported product, damage location, probable cause of failure, and the repair action planned or implemented. The more recent records include many more details on each pipeline failure. As described in [2], it is convenient to group the causes of pipeline failures into the following main categories.

1) Material failures which include weld defects, pipe wall cracking, fabrication defects, fatigue, etc.

2) Equipment failures to include failures in clamps, valves, ring gasket, flanges, pipeline connectors, etc.

3) Operational errors such as over-pressure in the line, pigging, fire/explosion.

4) Corrosion or erosion on the inside or the outside of the pipe.

5) Natural hazards such as hurricane storms and mud slides.

6) Third party damage due to anchor lines or anchor, jack-up rigs, construction vessels, supply boats, trawling, and dropped objects.

Figure 2 shows a histogram for the annual pipeline failures in the GOM during the ten year period of 1983-1992. Failures due to above causes and to storms and mud slides are included. Prior to 1992, the only year with significant storm related damage to pipelines was 1985, which had 55 failures resulting from four hurricanes (Juan, Elena, Danny, and Kate). Figure 3 shows similar data

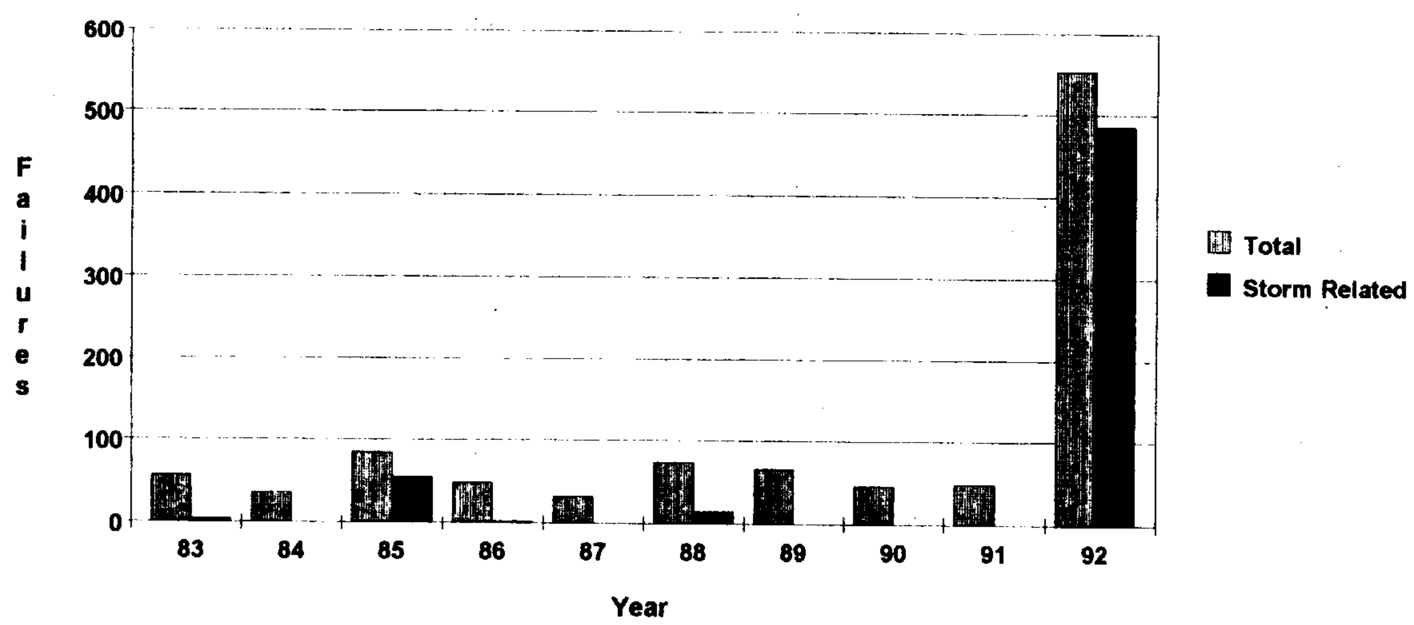



Figure 2: Pipeline Failures During 1983-92

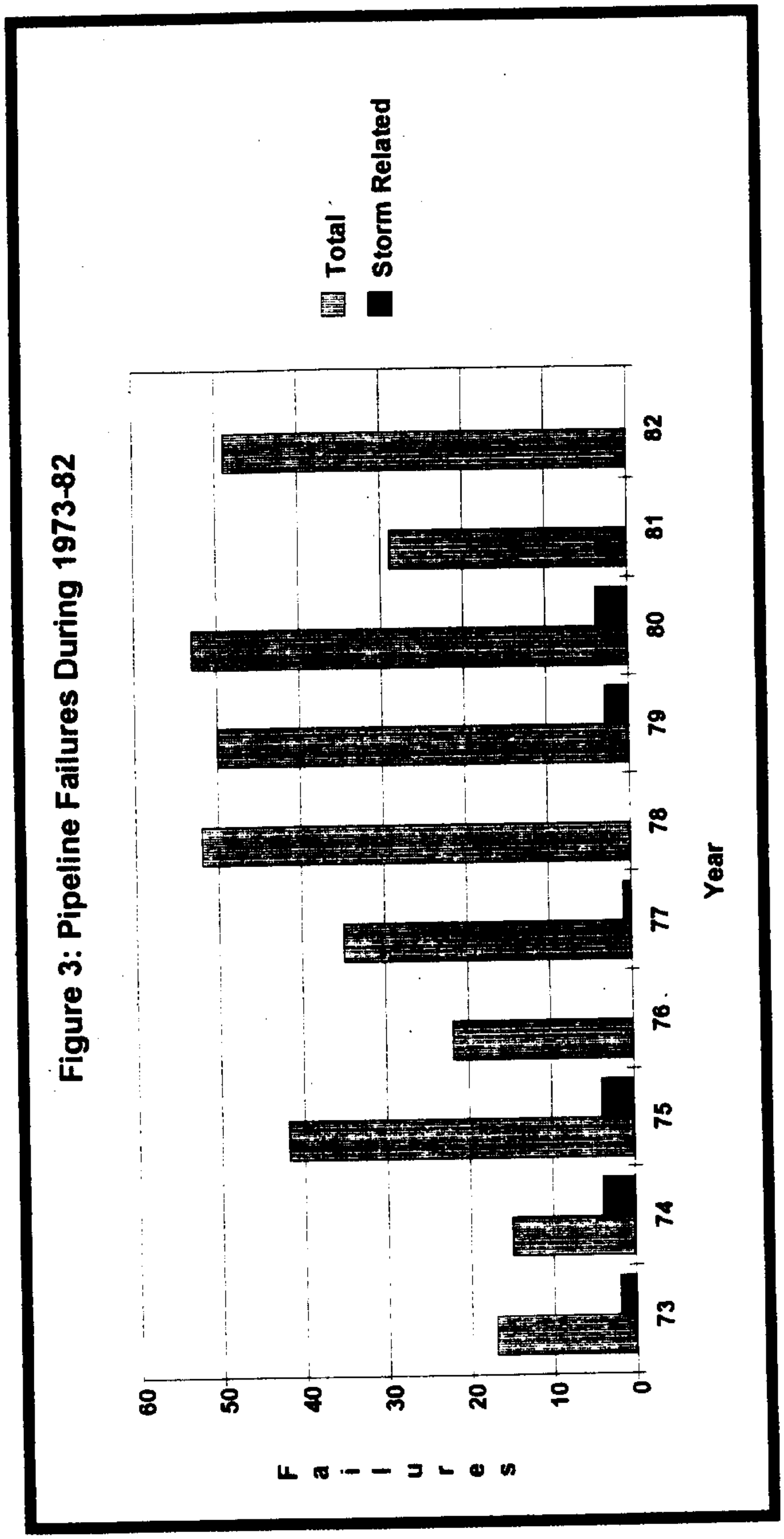



Figure 3: Pipeline Failures During 1973-82

on pipeline failures during the ten year period 1973-1982. Note that this figure is drawn to a different scale in order to more clearly show the number of storm related failures. During this period, the total number of storm related failures was very small. A review of the entire MMS database shows that during the period 1967-1984, there were only 25 storm and mud slide related failures. This compares with over 480 pipeline failures due to Hurricane Andrew and shows the enormity of the damage inflicted by Andrew. Table 1 lists the total number of storm and mud slide related failures during the period 1967-1992. Table 2 lists the number of pipeline failures attributed explicitly to various hurricanes in the MMS database. Clearly, the damage that resulted from Hurricane Andrew was significantly greater than that due to any previous storm.

**Table 1. Storm Related Pipeline Failures, 1967-92.**

| Year 19__ | 71 | 73 | 74 | 75 | 77 | 79 | 80 | 83 | 85 | 86 | 88 | 92 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| No. of Failures | 3 | 2 | 4 | 4 | 1 | 3 | 4 | 4 | 55 | 2 | 15 | 485 |

**Table 2. Pipeline Failures During Various Hurricanes.**

| Hurricane | Date | No. of Failures |
|---|---|---|
| Edith | 9/17/71 | 1 |
| Eloise | 9/23/75 | 1 |
| Bob | 7/12/79 | 1 |
| Allen | 8/11/80 | 2 |
| Elena | 9/1/85 | 9 |
| Danny | 9/9/85 | 5 |
| Juan | 10/28/85 | 41 |
| Kate | 11/22/85 | 2 |
| Florence | 9/12/88 | 1 |
| Gilbert | 9/19/88 | 11 |
| Andrew | 8/28/92 | 485 |

## 3.1 Hurricane Andrew Data

The MMS data was analyzed with respect to pipe size, pipeline product, water depth, cause or nature of the failure, location of failure, etc. The analysis results are helpful in identifying significant failure trends. The following sections describe the evaluation of failure data relative to the major points listed above.

### *3.1.1 Pipe Size*

Figure 4 shows the total number of line segments in each pipe size (nominal diameter) damaged during Hurricane Andrew. This figure shows that the largest number of failures were among the 4" size lines. A recent study by Williamson [5] has shown that within the corridor affected by Andrew the largest number of pipeline segments were of the 4" size. However, the number of failures in this size exceeds the proportion of 4" size lines that have been estimated to be in the storm path. It is generally known that the storm affected area included a large number of flow lines and small diameter pipelines. For the sake of analysis, it is convenient to divide the pipe sizes into three groups; namely: small size (2" to 6" OD), medium size (8" to 16" OD) and large size (18" and over OD) [2]. By grouping the number of failures like this, it can be seen from Figure 5 that about 86% of the damaged lines were from the small size group, 11% were from the medium size group, and 2% were from the large size group. This distribution is consistent with the results presented by Mandke on previous storms [2]. Williamson's data [5] shows that within the corridor affected by Andrew, 80% of the lines were of small size, 18% of medium size, and 2% of large size.

Since several of the platforms and other structures supporting the pipelines were damaged during Hurricane Andrew, failures of these associated pipelines can be attributed to failure of the structure. Hence, it is worth reviewing pipeline failure data excluding the records where the platform failed. This is shown in Figure 6. The failure distribution is similar to the overall data presented in Figure 4. By grouping the data according to the pipe size group, it can be seen from Figure 7 that the total percentage of small size lines that failed without damage to associated platform is 84%, which is close to the results given in Figure 5. Other pipe size groups also have failure rates that are in proportion to the entire data set.

The MMS database lists the failed pipelines along with the associated segment number assigned to each section of the pipeline. Table 3a lists the total length of all of the segments that were damaged during Hurricane Andrew. Table 3b shows the total lengths of the pipeline segments grouped according to pipe size. A total of about 766 miles of pipeline segments were affected by Andrew. It was not possible to determine the total length of the pipelines that existed in the corridor affected by Andrew.

### *3.1.2 Failure Cause*

All reported failures were grouped according to cause and location of the damage. Table 4 shows the total number of failures in each pipe size that can be attributed to the identified primary causes. They include damage to or loss of the platforms or the wellhead jackets and caissons, mud slides impacting pipeline, third party damage from drifting vessels, loss of anodes and the protective cover, and damage to pipelines and risers from excessive movement of the pipeline or the platform

Figure 4: No. of Failures per Pipe Size

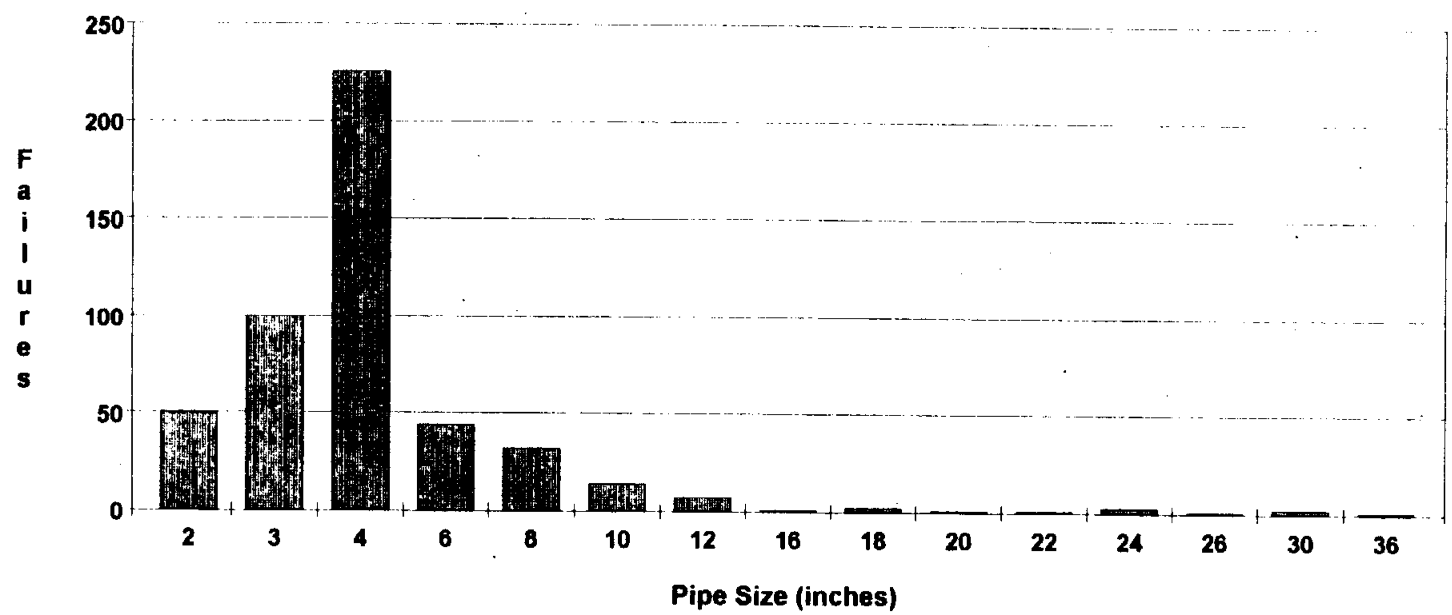
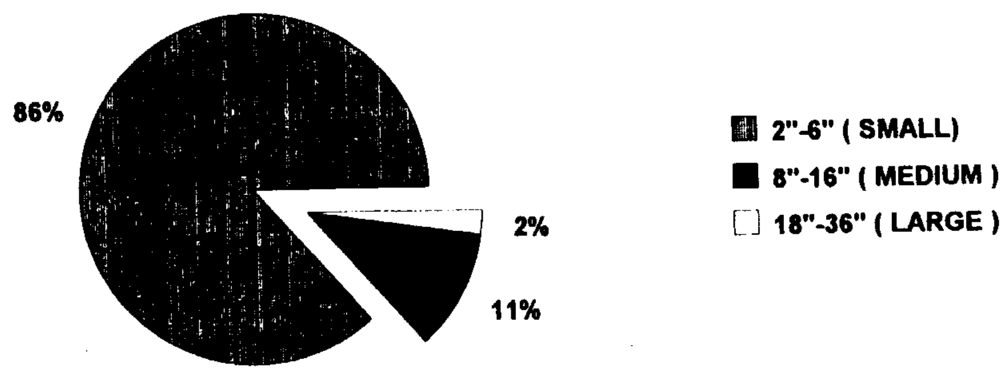


Figure 5: Failures per Pipe Size Group



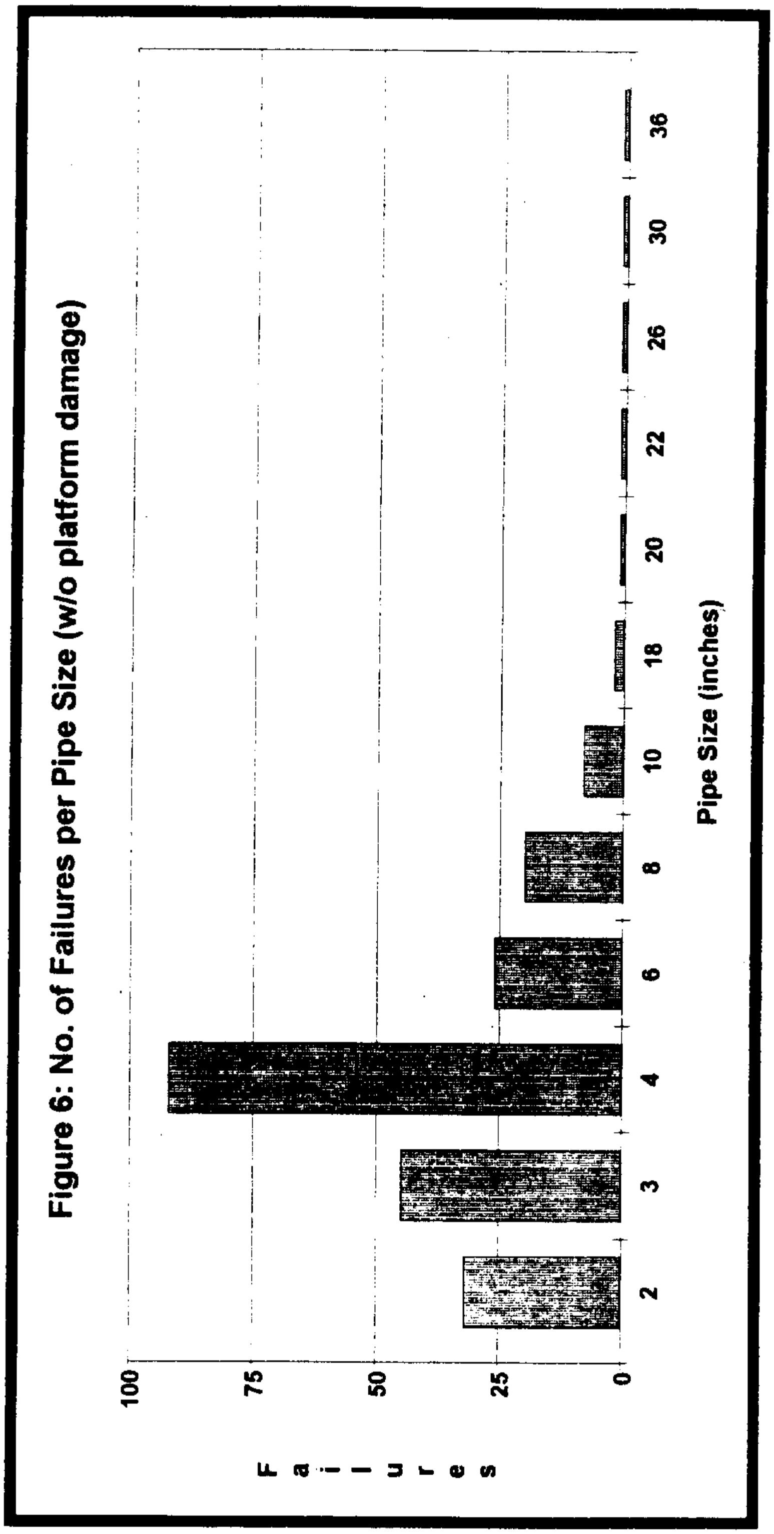


Figure 6: No. of Failures per Pipe Size (w/o platform damage)

Figure 7: Failures per Pipe Size Group (w/o platform damage)

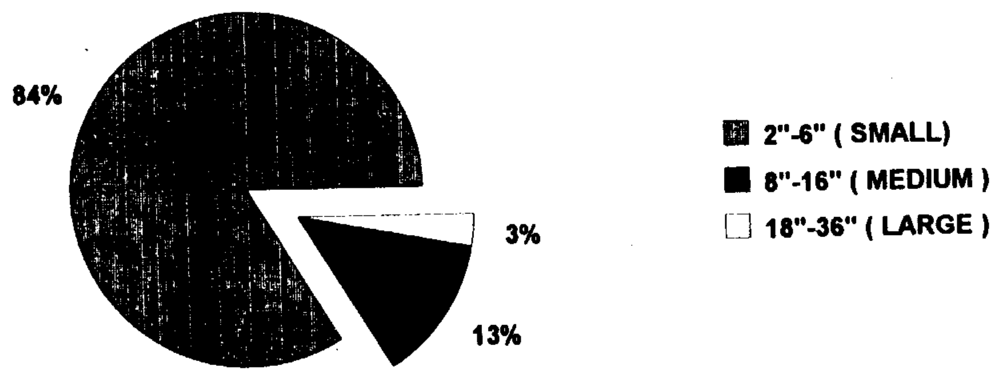


Table 3a. Damaged Line Lengths by Pipe Size.

| Pipe Size (inches) | Total Length (miles) |
|---|---|
| 2 | 25.1 |
| 3 | 52.3 |
| 4 | 146.8 |
| 6 | 84.9 |
| 8 | 90.0 |
| 10 | 36.7 |
| 12 | 73.0 |
| 16 | 5.0 |
| 18 | 24.3 |
| 20 | 102.9 |
| 22 | 31.8 |
| 24 | 49.3 |
| 26 | 22.2 |
| 30 | 0.2 |
| 36 | 21.0 |

Table 3b. Damaged Line Lengths by Pipe Size Group.

| Pipe Size Group (inches) | Total Length (miles) |
|---|---|
| Small (2-6) | 309.1 |
| Medium (8-16) | 204.7 |
| Large (18-36) | 251.7 |

## Table 4. Pipeline Damage Cause.

| Pipe Size (inches) | Mud Slide | Platform Damage | Riser Damage (1) | Pipeline Damage (2) | Anchor Damage (3) | Loss of P/L Anodes | Loss of D/L Cover | Other (4) | Total |
|---|---|---|---|---|---|---|---|---|---|
| 2 | - | 18 | 14 | 6 | - | 11 | - | 1 | 50 |
| 3 | - | 55 | 35 | 3 | - | 5 | - | 2 | 100 |
| 4 | - | 134 | 37 | 23 | 11 | 12 | - | 9 | 226 |
| 6 | 1 | 18 | 12 | 5 | 3 | - | - | 5 | 44 |
| 8 | 4 | 12 | 5 | 6 | 2 | - | 1 | 2 | 32 |
| 10 | 4 | 6 | - | 1 | 1 | - | 2 | - | 14 |
| 12 | - | 5 | - | - | - | - | 2 | 1 | 8 |
| 16 | - | 1 | - | - | - | - | - | - | 1 |
| 18 | 1 | - | - | - | - | - | - | - | 1 |
| 20 | - | - | - | - | 1 | - | - | - | 1 |
| 22 | - | - | - | - | - | - | 1 | - | 1 |
| 24 | - | 3 | - | - | - | - | - | - | 3 |
| 26 | - | - | - | - | - | - | 1 | - | 1 |
| 30 | - | 1 | - | - | - | - | 1 | - | 2 |
| 36 | - | - | - | - | - | - | 1 | - | 1 |
| Total | 10 | 253 | 103 | 44 | 18 | 28 | 9 | 20 | 485 |

**NOTES:**

(1) Damage due to excessive pipeline/platform movement or inadequate riser clamp support.
(2) Damage from excessive pipeline movement.
(3) Damage from anchors or anchor lines from drifting drilling vessels.
(4) Includes flare stack, lines modified to tie-in replaced structures, and lines with unknown damage cause.

during the storm. It should be noted that although in Table 4 each damaged pipeline has been assigned to a primary cause category, many of the pipelines could have been placed in more than one category. For example, the mud slide related failures could have been listed in the pipeline damage category. Pipeline damage attributed to damaged platforms could have been grouped in riser damage or pipeline damage, depending on the interpretation of the damage report from the operator. About 253 pipeline segments were damaged because of the failure of the associated platform structure. This accounts for more than half of the total number of failures.

There were 10 failures due to mud slides. They were among pipe sizes of 6" to 18" in diameter with the majority in the medium pipe size group. Most of the mud slides resulted in separation of the break-away joint, if present. Three cases resulted in damage to the associated riser and the pipeline section close to the platform. In five cases, only the break-away joint separated without damage to either the pipeline or the riser. Two incidents required replacement of 1000 feet and 2630 feet of pipeline segment, respectively.

About 103 cases of riser damage occurred that were attributed to either excessive platform movement, inadequate riser support clamps, or movement of the associated pipelines on seabed. All of these incidents were limited to pipes of less than 8" nominal diameter. This total also includes cases where only the riser to pipeline tie-in was damaged or where both the riser and the pipeline needed repair. For the 44 incidents of pipeline damage listed in Table 4, the primary cause was excessive movement of the pipeline. They required only repair of the pipeline section. Again, as in the case of riser damage, damage to pipeline sections was mostly limited to pipe sizes of less than 8" nominal diameter.

Third party damage to pipelines resulted in about 18 failures. As stated earlier, these were primarily due to unattended drilling vessels which drifted from their anchored positions during the storm. Sixteen failures of the pipeline sections resulted from either damage from the anchors or from the anchor chains of the drifting vessels. In two incidents, a jack-up rig positioned close to a platform damaged the risers from direct impact. The majority of failures occurred on lines with sizes between 4" and 10" in diameter. One 20" oil line was damaged from the anchor of a drifting vessel which resulted in significant release of oil into the sea. Only a 60' section of this line had to be replaced for the repair. The rig that caused this damage had been removed from service and anchored but broke loose during the storm and drifted.

About 28 small diameter lines with sizes 2"-4" lost anodes. Eighteen of these incidents resulted in damage to associated risers. It seems that these lines which were mostly installed for self burial, moved significantly towards the platform during the storm. This movement may have been the due to a loss of soil friction restraint on the pipeline during the storm and the pipeline expansion forces due to internal pressure and temperature. It is interesting that none of the larger diameter (> 6") lines experienced this type of failure.

The majority of pipelines that were damaged by Hurricane Andrew were in water depths less than 200 feet. For these lines, the regulation requires that all lines should have been buried to three feet below the seabed. There were nine incidents where the lines were exposed or lost the cover after the storm. All of these cases were among the lines with sizes in the range 8" to 36" in diameter.

These lines did not move out of the trench. None of these incidents resulted in damage to pipe wall and required only reburial of the line or replacement of the lost cover.

In addition to the above, the failure data included one 12" size flare line that was damaged and four pipeline segments were modified to tie-in with replacement platform structures. For about 15 incidents, the failure cause was not identified.

In Figure 8, each type of failure has been grouped by pipe size (small, medium, and large by their percent contribution). Thus, for mud slides, the largest number of failures (80%) were among medium size (8"-16") lines. The failures associated with damaged platforms were highest among the small size lines (89%) followed by 9% from medium size and 2% from large size lines. The small size lines generally associated with failures (95%) and with pipeline failures (84%). For both of these types of failures, there were no failures from large size pipe group. All failures with anode loss occurred among small size lines. Loss of pipeline cover occurred in 56% of the cases among medium size lines and in 44% of the cases among large size lines. Thus, each type of failure seems to have had a significant impact on lines of particular pipe sizes.

### *3.1.3 Damage Location*

The failure data was analyzed with respect to the location of the damage on the line. As shown in Table 5, the data for each pipe size was grouped according to whether the damage occurred on riser, the riser-to-pipeline tie-in, on both the riser and the adjacent pipeline section or only on the pipeline. The data presented in this table differs from the riser and pipeline damage data given in Table 4 which includes failures based on the primary cause of failure. The data in Table 5 includes failures due to all causes such as mud slides, third party damage, etc. It does not include failures associated with damaged platforms since the location of damage was not available and is not important. There were 94 incidents where the riser or the subsea tie-in were damaged. In 30 cases, both the riser and the pipeline were damaged and in 80 cases damage was limited to the pipeline section only. Figure 9 shows the results of grouping the data in Table 5 according to pipe size. Among the small size pipelines, the largest number of failures occurred in the riser or the subsea tie-in. Among the medium size lines, the number of failures in the riser section and the pipeline section are almost equal. For the large size lines, all failures occurred in the pipeline section.

### *3.1.4 Failures Grouped by Product*

Table 6 shows the failed pipelines grouped according to the transported product. The majority of 2" size lines that failed were service lines to satellite wells. The largest number of failures (218) occurred among lines transporting bulk oil. Failures among service lines to satellite wells, which are listed as lift and other service lines, totaled 119. There were 76 failures among lines transporting bulk gas. Flare and multi-phase flow lines accounted for 22 failures. In Table 7, the failure data is tabulated relative to the transmitted product after excluding all failures where the associated platform/structure failed. In this table, the bulk gas and processed gas lines have been combined together as gas lines. Similarly, the bulk oil and processed oil lines have been combined as oil lines. The lift lines have been combined with the remaining service lines. For the revised failure data, Table 7 shows that 110 failures occurred among oil lines.

Figure 8: Percent Failure Type per Pipe Size Group

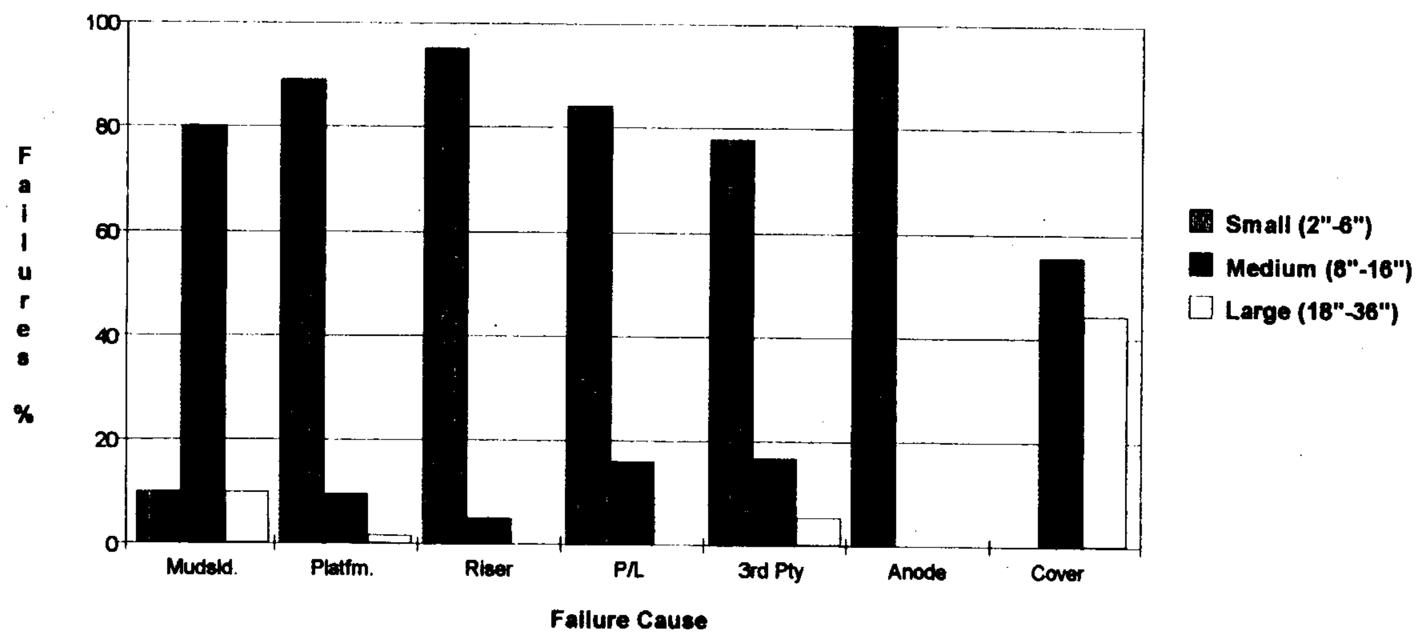


Table 5. Pipeline Damage Location (w/o Platform Damage).

| Pipe Size (Inches) | Riser Damage | Riser/Pipeline Tie-in | Both Riser & Pipeline | Pipeline Away From Platform | Other | Total |
|---|---|---|---|---|---|---|
| 2 | 13 | 1 | 11 | 6 | 1 | 32 |
| 3 | 33 | - | 4 | 6 | 2 | 45 |
| 4 | 28 | 3 | 11 | 41 | 9 | 92 |
| 6 | 8 | 3 | 2 | 8 | 5 | 26 |
| 8 | 5 | 4 | 2 | 7 | 2 | 20 |
| 10 | 1 | 3 | - | 4 | - | 8 |
| 12 | - | - | - | 2 | 1 | 3 |
| 18 | - | - | - | 1 | - | 1 |
| 20 | - | - | - | 1 | - | 1 |
| 22 | - | - | - | 1 | - | 1 |
| 26 | - | - | - | 1 | - | 1 |
| 30 | - | - | - | 1 | - | 1 |
| 36 | - | - | - | 1 | - | 1 |
| Total | 88 | 14 | [illegible] | 80 | 20 | 232 |

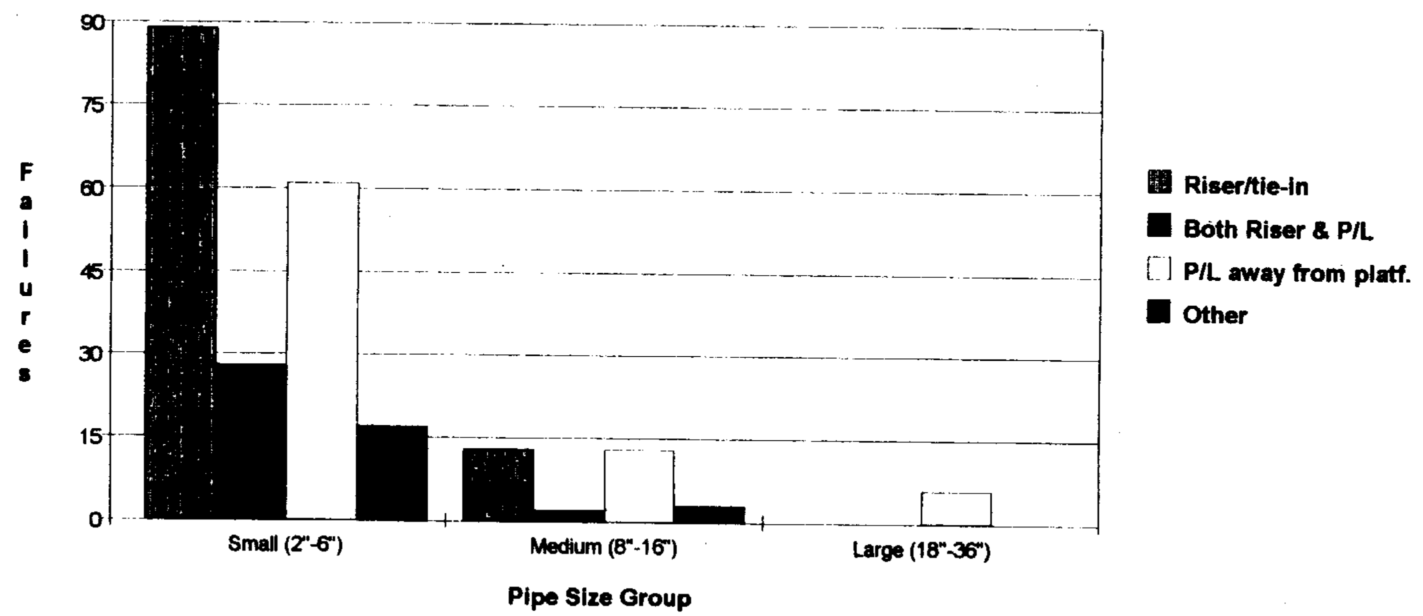



Figure 9: No. of Failures by Damage Location

**Table 6. Damaged Pipelines Grouped by Product.**

| Pipe Size (inches) | Bulk Gas | Gas | Bulk Oil | Oil | G/O or G/C | Lift | Other Serv. | Flare | Total |
|---|---|---|---|---|---|---|---|---|---|
| 2 | 3 | - | 3 | - | - | 28 | 16 | - | 50 |
| 3 | 6 | 1 | 54 | - | 1 | 38 | - | - | 100 |
| 4 | 58 | 2 | 124 | 5 | 4 | 21 | 6 | 6 | 226 |
| 6 | 7 | 5 | 16 | 3 | 4 | 3 | 5 | 1 | 44 |
| 8 | 2 | 6 | 16 | 3 | 2 | - | 2 | 1 | 32 |
| 10 | - | 6 | 5 | 2 | - | - | - | 1 | 14 |
| 12 | - | 5 | - | 1 | 1 | - | - | 1 | 8 |
| 16 | - | 1 | - | - | - | - | - | - | 1 |
| 18 | - | 1 | - | - | - | - | - | - | 1 |
| 20 | - | - | - | 1 | - | - | - | - | 1 |
| 22 | - | 1 | - | - | - | - | - | - | 1 |
| 24 | - | 3 | - | - | - | - | - | - | 3 |
| 26 | - | 1 | - | - | - | - | - | - | 1 |
| 30 | - | 2 | - | - | - | - | - | - | 2 |
| 36 | - | 1 | - | - | - | - | - | - | 1 |
| Total | 76 | 35 | 218 | 15 | 12 | 90 | 29 | 10 | 485 |

**Table 7. Damaged Pipelines By Product (w/o Platform Damage).**

| Pipe Size (inches) | Gas | Oil | Service Flow lines | Misc. | Total |
|---|---|---|---|---|---|
| 2 | - | 2 | 30 | - | 32 |
| 3 | 1 | 32 | 12 | - | 45 |
| 4 | 29 | 41 | 18 | 4 | 92 |
| 6 | 6 | 11 | 7 | 2 | 26 |
| 8 | 1 | 16 | 2 | 1 | 20 |
| 10 | 1 | 6 | - | 1 | 8 |
| 12 | 1 | 1 | - | 1 | 3 |
| 18 | 1 | - | - | - | 1 |
| 20 | - | 1 | - | - | 1 |
| 22 | 1 | - | - | - | 1 |
| 26 | 1 | - | - | - | 1 |
| 30 | 1 | - | - | - | 1 |
| 36 | 1 | - | - | - | 1 |
| Total | 44 | 110 | 69 | 9 | 232 |

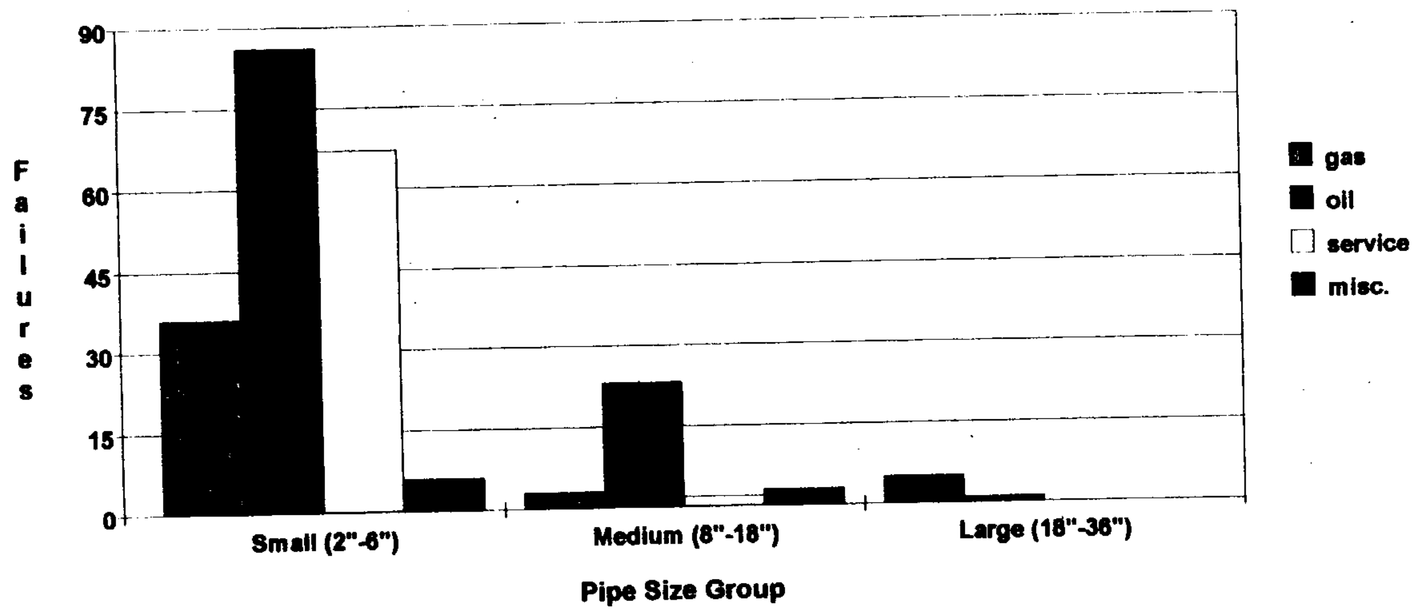
Gas line failures totaled 44. Williamson's data [5] shows that there were 1084 oil lines and 924 gas lines in the corridor affected by Andrew. The MMS database shows that through 1992, the total length of small size (2"-6") lines installed in the GOM are as follows: oil + bulk oil - 2193 miles, gas + bulk gas - 3166 miles. Lengths of the oil and gas lines that existed within the area affected by Andrew are not known. It seems that a disproportionately higher number of oil lines failed compared to gas lines. The reason for this trend is not clear. Service flow line failures amounted to 69, after excluding the failures related to damaged platforms.

Figure 10 shows the failed pipelines grouped by pipe size, and the corresponding distribution of the transported product. Thus, for the small and the medium size lines, the largest number of failures were among the oil lines. For the large size lines, the majority of failures were among gas lines. There was only one oil line failure in the large pipe size group. Most of the service line failures were in the small size line group.

### *3.1.5 Age of Damaged Lines*

In the aftermath of Andrew, it was initially suspected that the large number of lines damaged were perhaps very old and designed to a 25-year storm criteria. Also, with increasing age, lines are expected to deteriorate in strength due to corrosion and erosion and are thus more likely to fail. However, an analysis of Andrew data shows that this supposition is not necessarily valid for storm

Figure 10: No. of Damaged Pipelines by Product (w/o platform damage)



related pipeline failures. Table 8 shows the failed lines grouped according to their pipe size and the pipe's age at failure. The table excludes failures associated with damaged platforms and other structures. The age of each failed pipeline was determined based on the recorded hydro test date. Where the hydro test date was not available, then the approval date for the line segment was used. The majority of failed pipelines (136) were 6-15 years old. There were only 13 lines that were more than 20 years old. Age could not be determined for 29 lines in the database.

Figure 11 shows the failed lines grouped according to age group and pipe size group. Total failures within each pipe size group are expressed as percent failures. Thus, within the small size pipe group, 63% of the failed lines had ages less than 10 years, 22% were 11 to 20 years old, 4% were 21-30 years old, 1% were 31-40 years old. For the remaining lines, age is not known. The age distribution for medium size lines which failed was: 26% for less than 10 years old, 39% for 11-20 years old, 7% for 21-30 years old, 3% for 31-40 years old and 25% with unknown age. For the large size lines, 83% had an age 11-20 years and 17% had an with age of 21-30 years. So, there is no clear correlation between the age of the line and its failure frequency due to the storm.

### *3.1.6 Failures by Water Depth*

The failure database does not contain information on the exact water depth where damage occurred. This information was extracted, where available, from the segment number of the damaged pipeline. Table 9 shows the failed pipelines grouped according to water depth range for each pipe size. For 180 lines, the data on the water depths was not available. Among the remaining lines, the majority of failures occurred within 70 feet of water depth. Table 10 shows similar data after excluding failed lines associated with damaged platforms. In this case, data for water depths was not available for 71 lines. For the remaining 161 failed lines, 145 failures occurred in water depths of less than 60 feet.

In Figure 12, data for failed lines is presented in terms of water depth ranges and pipe size groups. Failures within each pipe size group are expressed as percentages. The majority of small size line failures occurred in water depths of less than 50 feet; for the large size pipes, they occurred within 51-100 feet of water depth. From this figure, it is apparent that most of the failures for all pipe size groups occurred in a water depth of less than 100 feet.

### *3.1.7 Pollution From Damaged Lines*

Within the MMS data base, there was only one incident with oil spill resulting from pipeline damage. This was a 20" size oil line which was damaged by an anchor from a drifting drilling rig. The line released about 2000 bbl of oil in to the sea. Reference 1 reports 10 other incidents with small quantities of oil release. The total oil spillage from these ten failures was estimated to be 500 bbl. Thus, excluding one major incident, the pollution from damaged pipelines during Hurricane Andrew has been insignificant.

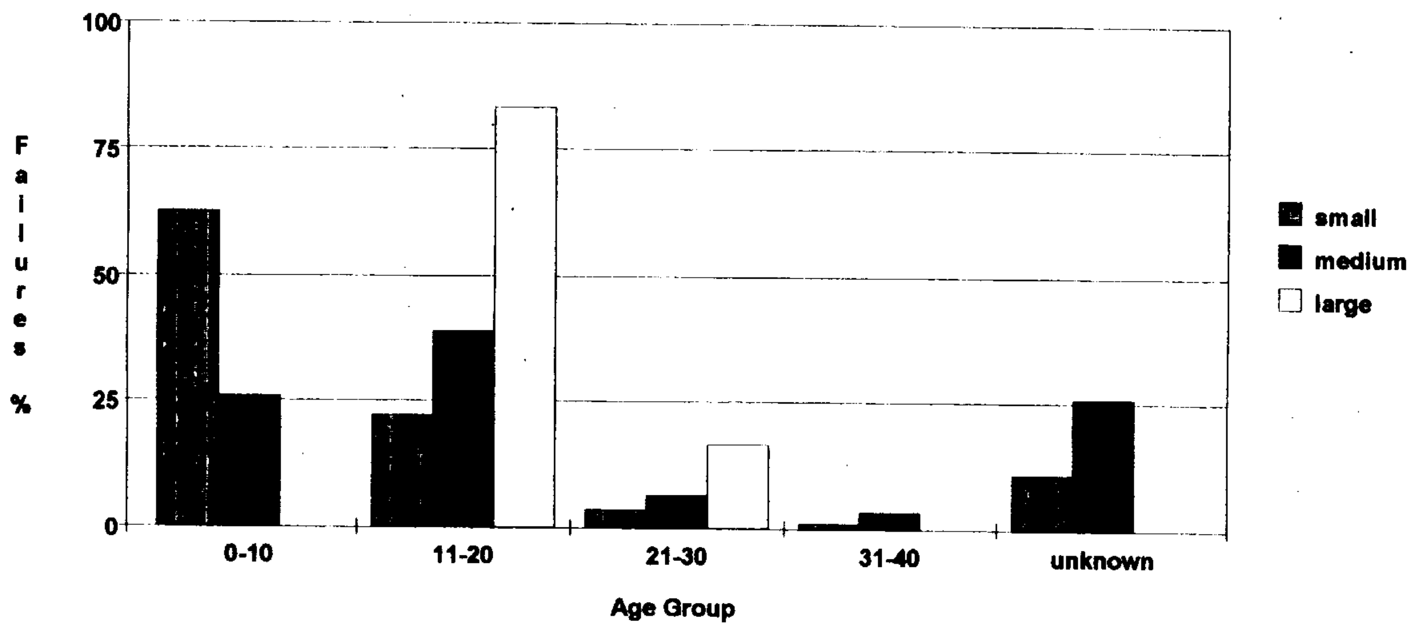
## 3.2 Pre-Andrew Storm Failure Data

There were 97 storm and mud slide related pipeline failures during the period 1967 to 1991. These data were analyzed to compare the results with damage from Hurricane Andrew. The data are

**Table 8. Age of Failed Pipelines (w/o Platform Collapse).**

| Pipe Size (inches) | Age (years) | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | < 5 | 6-10 | 11-15 | 16-20 | 21-25 | 26-30 | 31-40 | Unknown |
| 2 | 7 | 15 | 4 | 5 | - | - | - | 1 |
| 3 | 9 | 19 | 4 | 7 | 3 | - | - | 3 |
| 4 | 16 | 44 | 17 | - | 2 | - | 1 | 12 |
| 6 | 5 | 7 | 5 | 1 | 2 | - | 1 | 5 |
| 8 | 1 | 4 | 6 | - | 1 | - | 1 | 7 |
| 10 | - | 3 | 3 | 1 | 1 | - | - | - |
| 12 | - | - | 1 | 1 | - | - | - | 1 |
| 18 | - | - | - | 1 | - | - | - | - |
| 20 | - | - | - | 1 | - | - | - | - |
| 22 | - | - | 1 | - | - | - | - | - |
| 26 | - | - | - | - | 1 | - | - | - |
| 30 | - | - | 1 | - | - | - | - | - |
| 36 | - | - | 1 | - | - | - | - | - |
| Total | 38 | 92 | 43 | 17 | 10 | 0 | 3 | 29 |

Figure 11: Percent Failures by Age Group (w/o platform damage)



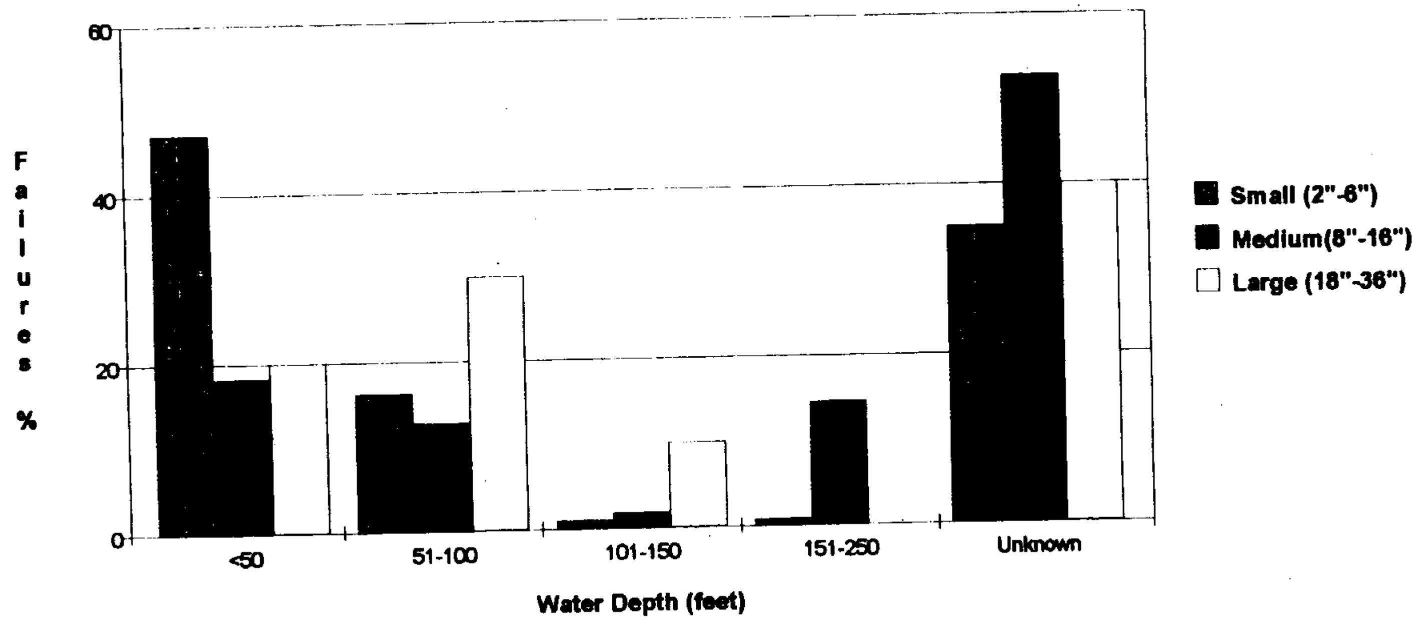
## Table 9. Pipeline Damage by Water Depth (feet).

| Pipe Size (Inches) | Water Depth Range (feet) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 11-20 | 21-30 | 31-40 | 41-50 | 51-60 | 61-70 | 71-80 | 81-90 | 91-100 | 101-150 | 151-250 | Unknown | Total |
| 2 | - | 20 | 6 | 2 | 1 | - | - | - | 1 | 1 | - | 19 | 50 |
| 3 | - | 19 | 18 | 12 | 9 | 1 | - | - | - | 1 | - | 40 | 100 |
| 4 | 5 | 36 | 32 | 42 | 40 | 6 | - | - | 3 | - | - | 72 | 225 |
| 6 | 1 | 5 | 3 | 7 | 2 | 1 | 3 | 1 | - | 2 | 3 | 16 | 44 |
| 8 | - | - | 6 | 1 | 3 | 1 | - | - | 1 | 1 | 5 | 14 | 32 |
| 10 | - | - | - | 1 | 2 | - | - | - | - | - | 3 | 8 | 14 |
| 12 | - | - | 2 | - | - | - | - | - | - | - | - | 6 | 8 |
| 16 | - | - | - | - | - | - | - | - | - | - | - | 1 | 1 |
| 18 | - | - | - | - | - | - | - | - | - | - | - | 1 | 1 |
| 20 | - | - | - | - | - | - | - | - | - | 1 | - | - | 1 |
| 22 | - | - | - | - | - | - | - | - | - | - | - | 1 | 1 |
| 24 | - | - | - | - | - | 1 | - | - | 2 | - | - | - | 3 |
| 26 | - | - | 1 | - | - | - | - | - | - | - | - | - | 1 |
| 30 | - | - | 1 | - | - | - | - | - | - | - | - | 1 | 2 |
| 36 | - | - | - | - | - | - | - | - | - | - | - | 1 | 1 |
| Total | 6 | 70 | 69 | 65 | 57 | 10 | 3 | 1 | 7 | 6 | 11 | 180 | 485 |

## Table 10. Pipeline Damage by Water Depth (w/o Platform Damage).

| Pipe Size (inches) | Water Depth Range (feet) | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 11-20 | 21-30 | 31-40 | 41-50 | 51-60 | 61-70 | 71-80 | 81-90 | 91-100 | 101-150 | 151-250 | Unknown | Total |
| 2 | 1 | 19 | 3 | 1 | - | - | - | - | - | 1 | - | 7 | 32 |
| 3 | - | 14 | 10 | 3 | 3 | - | - | - | - | - | - | 15 | 45 |
| 4 | 2 | 18 | 14 | 14 | 17 | 4 | - | - | - | - | - | 23 | 92 |
| 6 | 1 | 1 | 6 | 6 | 1 | - | - | 1 | - | - | 2 | 8 | 26 |
| 8 | - | - | 3 | 1 | 3 | - | - | - | - | - | 4 | 9 | 20 |
| 10 | - | - | - | 2 | - | - | - | - | - | - | 3 | 3 | 8 |
| 12 | - | - | - | - | - | - | - | - | - | - | - | 3 | 3 |
| 18 | - | - | - | - | - | - | - | - | - | - | - | 1 | 1 |
| 20 | - | - | - | - | - | - | - | - | - | 1 | - | - | 1 |
| 22 | - | - | - | - | - | - | - | - | - | - | - | 1 | 1 |
| 26 | - | - | 1 | - | - | - | - | - | - | - | - | - | 1 |
| 30 | - | - | 1 | - | - | - | - | - | - | - | - | - | 1 |
| 36 | - | - | - | - | - | - | - | - | - | - | - | 1 | 1 |
| Total | 4 | 52 | 38 | 27 | 24 | 4 | - | 1 | - | 2 | 9 | 71 | 232 |

**Figure 12: Percent Failures by Water Depth**



available mostly in hard copy format and do not include information on several items that are included in the computer database. As such, the analysis has been limited to only a few items such as pipe size, transportation product, damage type, and pollution.

Table 11 shows a breakdown of pipe sizes for storm related pipeline failures that occurred during 1967 to 1991. Only the years with storm or mud slide related failures have been listed. As stated earlier, there were 55 storm/mud slide related failures in 1985 and 15 failures in 1988. For all other years where storm damage occurred, the total number of failures were less than five.

Figure 13 shows the percent distribution of all 97 failures among the three pipe sizes. This figure shows that the largest number of failures (69%) occurred among the small size lines. In order to allow for comparison with Andrew data, the storm related failures have been separated from the mud slide related data in Figure 14. For storm related damages, small-size pipelines accounted for about 87% of the total failures, which is close to the results of the Andrew data. In making this comparison, it should be noted that Andrew resulted in only a small number of failures due to mud slides and is dominated by storm related failures. For rigorous analysis, both sets of data can be compared after excluding the mud slide related failures. The majority (73%) of pre-Andrew mud slide related failures were from the medium size pipe group (Table 12). Again, this is consistent with the results from Andrew. Like Andrew, the majority of damage occurred on small size pipelines at or near the risers, and the majority of damage among medium and large size pipes occurred on pipeline sections located on the seabed.

Table 13 and Figure 15 show pre-Andrew damage distributions, grouped by pipe size and transported product. Gas lines shown include both bulk gas and processed gas; oil lines include bulk oil and processed oil. All types of service flow lines are grouped together. Within the small size pipe group, the largest number of failures occurred on oil lines, followed by service flow lines. In the medium size pipe group, oil line failures occurred much more frequently than gas lines failures. All large pipe size lines were gas lines. It is worth noting that a similar distribution by product existed among failed lines due to Hurricane Andrew.

Pollution from lines that failed prior to 1992 due to storms and mud slides has been very low. Table 14 lists all incidents with significant oil release for all storms that crossed the Gulf since 1967. Since most of the storm related damage has been on small size lines, the resulting pollution has been relatively small.

Summarizing, the pre-Andrew data has shown some similar trends to the data for Hurricane Andrew. They include:

- The majority of storm related failures occurred on lines of small pipe size (2"-6" OD)
- The majority of mud slide related failures occurred on lines of medium pipe size (8"-16" OD)
- The damage on small size pipelines occurred in the riser section or the riser-to-pipeline tie-in
- The largest portion of small size lines which failed were transporting oil.

Table 11. Pipeline Failures Due to Storms and Mud Slides (1967-91).

| Pipe Size (inches) | Year | | | | | | | | | | | Totals |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 71 | 72 | 74 | 75 | 77 | 79 | 80 | 83 | 85 | 86 | 88 | |
| 2 | - | - | - | - | - | - | 1 | - | 5 | 1 | 1 | 8 |
| 3 | - | - | - | - | - | - | - | - | 16 | - | 5 | 21 |
| 4 | 1 | 1 | - | 1 | - | - | 1 | - | 14 | 1 | 3 | 22 |
| 6 | 2 | 1 | 1 | - | - | - | 1 | 2 | 8 | - | 1 | 16 |
| 8 | - | - | 1 | 1 | - | 1 | 1 | 2 | 5 | - | 3 | 14 |
| 10 | - | - | - | - | - | - | - | - | 5 | - | 2 | 7 |
| 12 | - | - | 2 | 2 | 1 | 2 | - | - | - | - | - | 7 |
| 18 | - | - | - | - | - | - | - | - | 2 | - | - | 2 |
| **Total** | **3** | **2** | **4** | **4** | **1** | **3** | **4** | **4** | **55** | **2** | **15** | **97** |

Figure 13: Failures per pipe size group (1967-91)

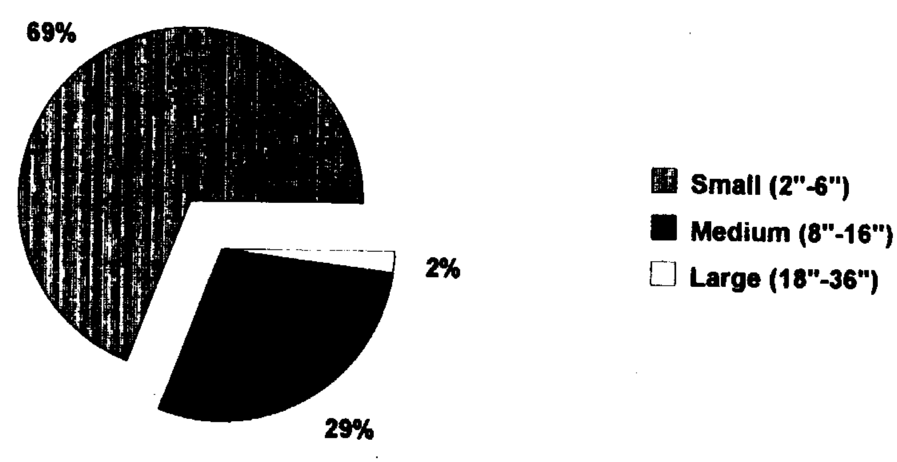
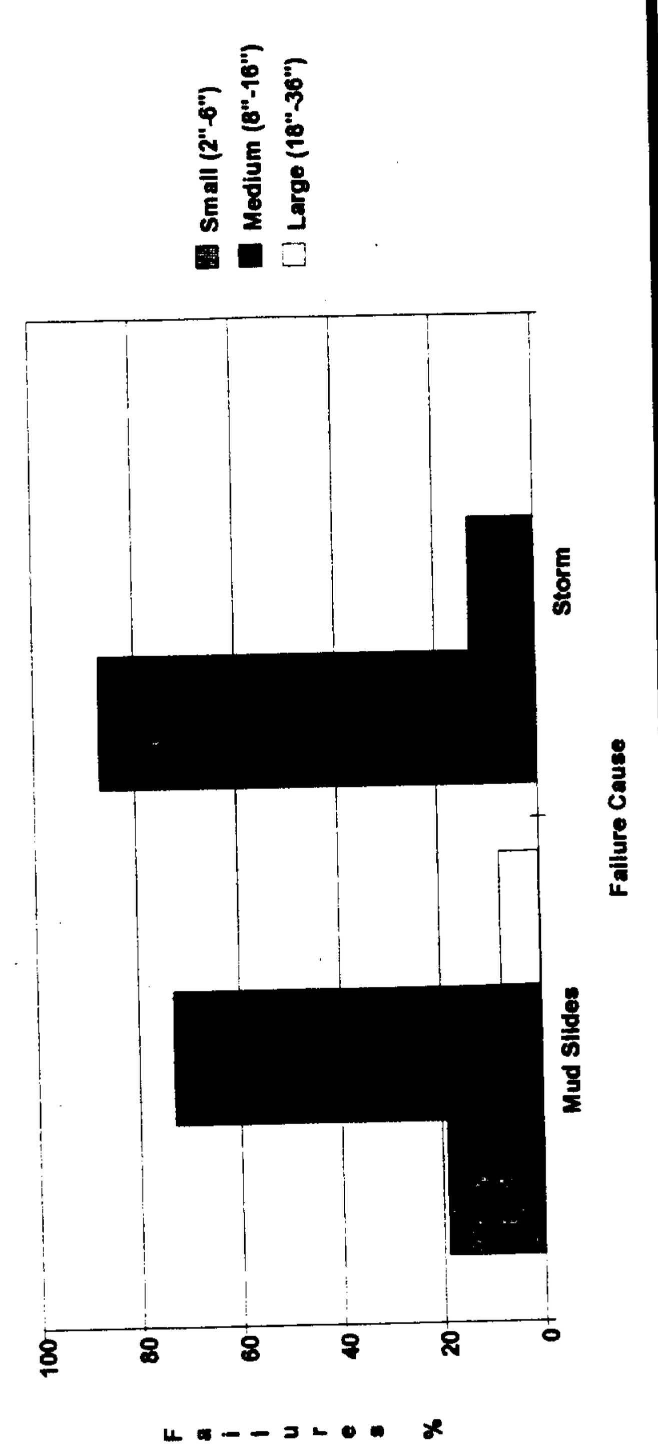


Figure 14: Percent Failures per Pipe Size Group (67-91)



## Table 12. Pipeline Damage Location (1967-91).

| Pipe Size (inch) | Riser Damage | Subsea Tie-In | Both Riser and Pipe | Pipeline | Unknown |
|---|---|---|---|---|---|
| 2 | 5 | 2 | 1 | - | - |
| 3 | 14 | - | - | 7 | - |
| 4 | 10 | - | 10 | 1 | 1 |
| 6 | 5 | - | 2 | 8 | 1 |
| 8 | - | 3 | 3 | 8 | - |
| 10 | - | - | 1 | 6 | - |
| 12 | - | - | - | 7 | - |
| 18 | - | - | 1 | 1 | - |
| Total | 34 | 5 | 18 | 38 | 2 |

Table 13. Damaged Pipelines by Product (1967-91).

| Pipe Size (inches) | Bulk Gas | Gas | Bulk Oil | Oil | Condensate | G/O | Lift | Test | Unknown |
|---|---|---|---|---|---|---|---|---|---|
| 2 | - | - | - | 1 | - | - | 6 | - | 1 |
| 3 | - | 3 | 1 | 8 | - | - | 5 | 4 | - |
| 4 | 1 | 5 | 1 | 12 | 1 | - | 2 | - | - |
| 6 | - | 3 | - | 9 | - | - | 1 | - | 3 |
| 8 | - | - | 3 | 11 | - | - | - | - | - |
| 10 | - | 2 | 1 | 3 | - | - | - | - | 1 |
| 12 | - | 1 | - | 5 | - | 1 | - | - | - |
| 18 | - | 2 | - | - | - | - | - | - | - |
| Total | 1 | 16 | 6 | 49 | 1 | 1 | 14 | 4 | 5 |

Figure 15: Damaged Lines by Product (67-91)

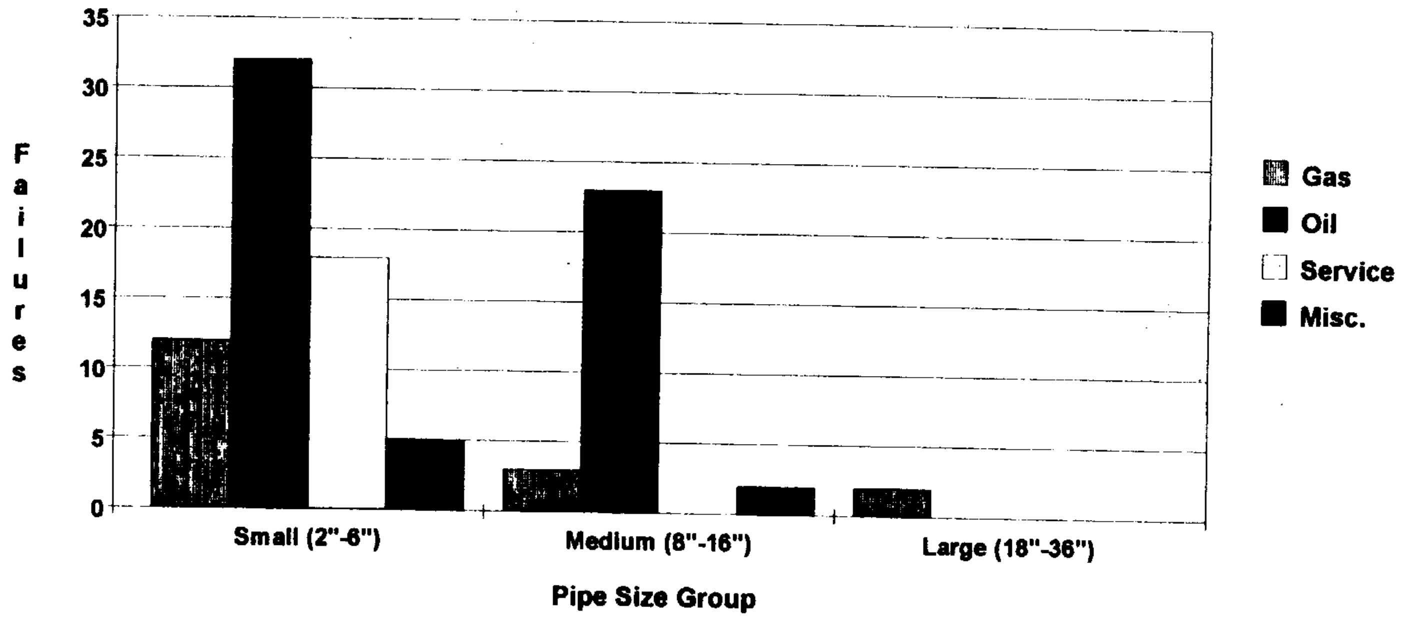


Table 14. Pollution From Pipelines Damaged by Storms.

| Data | No. of Failures | Pollution/Incident |
|---|---|---|
| 1967-91 | 1 | 250 bbl |
| | 1 | 80 bbl |
| | 5 | 10-20 bbl |
| | 6 | 1-2 bbl |
| | 3 | < 2 gal |
| 1992 (Andrew) | 1 | 2000 bbl |
| | 10 | 50 bbl (avg) |

## 4.0 PIPELINE DESIGN PROCEDURES

The analysis of pipeline failure data described in the previous section has shown that the three principal modes of failures are:

- Platform damage
- Riser damage
- Pipeline movement on the seabed

Several studies have been performed in recent years to increase the safety level and the performance of platforms and jacket structures during severe storms. Some of these studies were sponsored by MMS in the aftermath of Hurricane Andrew. The results of these studies have been incorporated in the platform design codes such as the twentieth Edition of API RP 2A [4]. Older platforms that were designed under the 25-year storm criteria or the older 100-year storm criteria are being evaluated under the revised 100-year storm criteria developed for the GOM. These older structures are being evaluated and modified as per the platform requalification methodology developed by the industry. It is anticipated that the measures currently being implemented by the industry will result in reduced damage to platforms during future hurricanes.

The remainder of this section includes a discussion of the current practices regarding pipeline and riser design. The intent is to address in general terms the significant design issues and the current practices regarding pipeline design for protection during severe storms. Areas of uncertainty either in the design methods or in the design parameters have been identified. Specific site related problems will require unique analyses methods and are not included in the following discussion.

### 4.1 Riser Design

Development of pipeline riser design methodology began in the mid-1970's [6]. The impetus for the initial work came from problems encountered in some of the early North Sea riser installations and the designs of the large diameter risers in the GOM. Several of the risers installed prior to this period may not have been designed and analyzed as per the current procedures. In 1976, DnV [7] published the first comprehensive guidelines addressing riser pipeline and riser design requirements. Subsequently these guidelines were modified in 1981 [8] to include the revised design safety factors for the risers. In the GOM, the industry has been using the ANSI B 31.8 code for gas lines and ANSI B 31.4 code for liquid pipelines. Both of these codes were initially developed for onshore pipelines and did not address offshore pipeline related problems explicitly. The recent edition of B 31.8 [9] does include a separate section explicitly addressing offshore pipelines. The Department of Transportation (DOT) issued requirements applicable to offshore gas and liquid pipelines around the late 1970's. These are mandatory requirements for lines that fall under the DOT jurisdiction. The different codes specify the allowable stress levels in the riser under various loading conditions. The loading conditions that need to be analyzed for a typical pipeline and riser include:

- Pipeline/riser under installation
- Pipeline/riser under normal operation
- Pipeline/riser under a severe storm (100-year)

It is the last loading condition listed above that will be discussed in detail here. Risers that are installed by pulling the pipeline through another pre-installed pipe on the platform, called a "J-tube", are excluded from this discussion. Static stress analysis of the riser section and the pipeline on the seabed is normally performed using finite element computer codes or piping analysis programs. The analysis uses the peak hydrodynamic loads acting on the riser and the pipeline, and the corresponding platform displacements affecting the riser supports. The analysis should include the:

- Dead weight of the riser
- Pressure and temperature effects
- Omnidirectional storm wave loading
- Storm current loading
- Platform displacement imposed at the clamp support points
- Flexibility of clamp supports
- Soil/pipe interaction on the seabed

Procedures for the analysis are quite well established and have become easy to implement with personal computers. As noted earlier, risers have failed when clamps are inadequately designed or a pipeline on the seabed moves excessively during a storm. Proper design analysis of the riser section will assure its survival under extreme storm conditions. It is suspected that for several of the small diameter risers that failed, the stress analysis was not performed adequately. Insufficient maintenance of risers and the supporting clamps could also have contributed to several riser failures. Some uncertainty exists in the riser analysis procedures currently being used for the pipe/soil interaction on seabed during a storm. The longitudinal soil friction force acting on the pipeline on the seabed is critical to determining the stresses imposed on the riser section. The industry has been successfully using conservative values for this parameter based on laboratory tests and field data.

## 4.2 On-Bottom Stability

Extensive research was performed by the industry during the mid-1980's on the problem of on-bottom stability of pipelines during a severe storm. Prior to this period, the in-place stability of pipelines on the seabed and the required concrete coating on the line was evaluated using a simplistic Coulomb friction model for the soil restraint on the pipeline, and the Morrison's equation approach to determine hydrodynamic loading effects. The hydrodynamic drag, lift and inertial force coefficients were initially developed for steady currents and later for oscillatory flow caused by wave action. During the 1980's, significant research was done in Europe, primarily by the Danish Hydraulic Institute in the area of the hydrodynamic loads on pipe and by SINTEF in Norway in defining the soil restraint acting on the pipe. In the United States, the AGA sponsored several research programs to develop a design methodology combining the results of various research programs [10]. At about the same time, the DnV published recommended design procedures for on-bottom stability of pipelines [11]. These procedures also were based on the results of research done in the areas of hydrodynamic loading and soil restraint performed earlier by the industry. Both methods, namely those of the AGA and the DnV, give quite similar results in most conditions. They represent the current state-of-the-art for on-bottom stability design. The current method of on-bottom stability design should have been implemented on lines designed after 1988.

It should be noted that for lines designed prior to the current guidelines, the previous approach resulted in generally conservative designs and seems to have worked adequately for medium and large size lines. For small size lines (2"-6" OD), the efficacy of the new, revised methods seems to be unclear. It was found in reviewing failure data for Hurricane Andrew that no pipeline failures occurred among the medium and large size lines installed after 1988. However, there were 18 failures for small lines designed and installed after 1988. These numbers exclude the pipeline failures associated with damaged platforms. Since most of these lines were required to be buried below the seabed, it is not clear if the failures can be attributed to inadequacy in the on-bottom design methods or to other potential failure mechanisms. Some of these failure scenarios are discussed later in this section.

Although the current AGA and DnV design procedures are very comprehensive, there is an area of uncertainty in the application of these methods for determining the soil friction force acting on the pipeline. For practical reasons, it is often difficult to determine the properties of the small layer of soil under the pipe or on top of the seabed in the vicinity of pipe. Also, most of the soil/pipe interaction test data used in these procedures are based on tests performed on medium and large diameter pipe samples. Whether small size pipes would behave in the same way is not clear.

## 4.3 Mud Slides

The Mississippi delta region of the GOM is known for mud slides that occur during severe storms. Soft sediment in this area gets deposited on sloping bottoms and interactions between the storm wave and the seabed can result in subsequent instability in the sloped soil layer. Given the soil properties and the geometry of the slope, techniques are available to determine if a particular slope will fail under the specified storm wave loading. Since the bottom terrain is changing continually, it is difficult to determine the load that will be imposed on the pipeline in the path of a mud slide. The current industry practice is to allow the pipeline to move during the mud slide, and to separate from the riser near the platform, through the use of break-away connectors. It is difficult to design a pipeline to withstand the load imposed by a mud slide. An alternative to break-away connectors is to use a flexible pipe jumper hose connection between the pipeline and the riser. The jumper hose is installed with a slack on the order of 100 feet or more. This allows the pipeline to move without damaging the riser.

Break-away connectors are designed for separation of the joint when a predetermined tensile load is imposed on the pipeline. They seem to have worked satisfactorily in half of the cases during Hurricane Andrew. In the remaining instances the connector did not separate or did damage to the riser or pipeline during its separation. This problem is being reviewed by the connector manufacturers. Connector failures have been attributed to ingress of oil and other contaminants, and to corrosion of the components. Flexible jumper pipe has several problems associated with it—it is more vulnerable to damage from foreign object impact, is difficult to repair, and can be expensive if long lengths are required.

## 4.4 Soil Liquefaction

In some areas of the Gulf, the potential for soil liquefaction under the influence of cyclic wave pressure acting on the seabed needs to be evaluated. If the shear strength of the soil is very low, then the possibility of pipe sinking needs to be evaluated. On the other hand, if the specific gravity of the buried pipe is likely to be lower than the specific gravity of the soil during the liquefaction, then the possibility of pipe flotation should be considered. Both the ANSI B 31.8 code [9] and the DnV [11] guidelines require checking for the vertical and horizontal stability of pipelines installed on soils with potential for liquefaction. However, very little guidance is provided in these documents on the procedures to be followed for verifying pipeline stability under these soil conditions. Nataraja, et al., [12] have developed a simplified method that can be adapted to review the stability of buried pipelines under the influence of wave induced soil liquefaction. Most of the available procedures are based on the evaluation of changes in shear stress in the soil due to cyclic wave pressure acting on the seabed. The analysis results are helpful to determine the vertical stability of the pipe. Methods for determination of lateral movement of the pipe after the soil has reached its liquefaction potential are not well established.

### 4.5 Buried Pipelines

Pipelines are sometimes protected against extreme hydrodynamic loads by trenching and burying them below the seabed, by installing them for self-burial in soft sediments, or by putting a protective external cover of gravel, sand bags or concrete mats over the pipe. In shallow water, these precautions might also be required by regulatory authorities. Such protective measures are needed for protection from fishing gear impact, dropped objects, dragging anchor chains, etc. Some technical aspects associated with these methods of pipe protection are discussed here.

Pipeline trenching in the GOM has been traditionally been performed by the jetting method. A jetting sled is mounted on the pipe and this cuts the surrounding soil using a high pressure water jet as it is pulled along the length of the pipeline. Jetting equipment is usually mounted on a bury barge. This method results in wide angle trenches in sandy soils and clays of medium strength. The equipment cannot be used easily on small diameter lines of sizes 2" to 4" due to the risk of damaging the line during trenching. Other methods of trenching such as using a plow or a mechanical trencher are not commonly used in the Gulf region.

Pipelines which are trenched and buried in consolidated soils will generally remain in place and provide adequate protection during a severe storm. For small size lines in soft sediments, a common practice is to install the lines for self-burial. Although this method does eventually lower the lines below the seabed, its stability during a severe storm seems to be major problem. During an extreme storm, the sediment around the pipe tends to be displaced which moves the pipeline out of place. Very little research has been done on the vertical and lateral break-out of lines which are self-buried. Some research on lines in loose, sandy, erodible soils has been done for lines in the North Sea [13,14]. These results cannot be applied to soft cohesive soils in the GOM. A better understanding is needed of pipeline behavior, especially of small size, in soft sediments during a 100-year storm condition.

The preceding discussion has identified the major factors that influence the design of the pipelines for protection during extreme storm conditions. Among the various associated problems, it seems that small size lines need more attention in the future to reduce any potential damage. An investigation of the currently followed procedures to determine their response to severe storms is required. In the meantime, it is recommended that, when possible, small size lines be piggy-backed with larger size lines. Where this is not feasible, the use of flexible jumper hoses with enough slack near the riser connection may be considered. This will protect the riser from damage during pipeline movement and also protect the line by allowing it to move during storm. Other design options should be evaluated, such as using siren anchors along the length of the line to secure it to the seabed.

## 5.0 POLLUTION MITIGATION

Pipelines that rupture during a storm will immediately release the contained hydrocarbons into the sea. There was only one significant oil spill during Hurricane Andrew. This was from a 20-inch oil line which was damaged by an anchor from a drifting mobile offshore drilling rig. Reference 1 reported a total of eleven spills, of which 10 produced minor slicks and rainbows having an estimated release of 500 barrels. The damaged 20-inch line released about 2000 barrels of oil. Subsequent estimates from MMS [5], including the amount of oil released from lines "pulled apart", add an additional 4200 barrels to the total amount of oil spillage from Andrew. Hence, considering the severity of Andrew and the number of lines that were damaged, the overall performance of all pipelines has been quite good in terms of pollution prevention. Consequently, the measures being taken by most of the operators to mitigate pollution during the storm seem to have worked satisfactorily.

Post storm pipeline inspection and line start-up procedures are important to avoid additional release of hydrocarbons from lines already damaged during the storm. Effective functioning of pipeline isolation devices and associated controls will limit the volume of oil that is released into the sea from damaged lines. This section summarizes the methods available to minimize oil spills from pipelines damaged during a severe storm.

### 5.1 Design Procedures

Design features which can be incorporated into a pipeline to reduce pollution include:

- Isolation valves
- Emergency shut down valves (ESD)
- Check valves
- Break-away joints with check valves
- Flexible jumper pipe with check valves

These last two items are specifically applicable to pipelines in potential mud slide areas. Break-away joints with check valves have also been used at subsea lateral tie-ins between a lateral branch line and the main trunk line. The isolation valves can be manually, automatic or remotely operated. Most of the ESDs are generally pressure activated. These devices essentially limit the amount of hydrocarbons that flow out of the line in the case of a rupture. The isolation devices, and most of the device controls, seem to have worked well during Hurricane Andrew. A separate study sponsored by MMS is in progress which will focus explicitly on the performance of safety and control devices during Hurricane Andrew. The results of this study will provide useful information on which to base future designs of pipeline isolation and control devices. In spite of using these isolation devices, large quantities of oil may be released in the event of a rupture in large diameter trunk lines. For such lines, other operating procedures may be considered as discussed later. Pipeline burial and backfilling, and using sand bags or concrete mats are other options that can protect against excessive movement during a storm and thus increase safety by reducing the potential for oil spills.

## 5.2 Operating Procedures

The pipeline operating procedures discussed here refer to line shut-in prior to a storm's arrival and subsequent start-up after the storm. There are no specific requirements stated by any regulatory body or pipeline code regarding pipeline shut-in procedures. Typically, gas lines are shut-in at full pressure and the oil lines are shut-in at reduced pressure. The infield flow lines are shut-in at the wellhead and could be left at the wellhead pressure. Shutting-in gas lines at full pressure is helpful in determining leaks from a reading of the pressure drop. However, if the lines are left at reduced pressure, they can accommodate a larger amount of lateral movement before yielding or rupture. Ideally, long distance oil lines should be emptied of oil by pigging them with gas or water before shut-down. This would avoid the potential of oil spillage from the ruptured line. For economic reasons, this solution is not practiced. Reducing the pressure in the oil line to a low level instead of completely depressurizing it has the benefit of being able to detect leakage from the reduced line pressure.

Bringing the pipeline back into production after a storm should not commence until the standard damage inspection procedures are completed and the integrity of the line is reasonably confirmed. For lines that are shut-in at reduced pressure, the flow rate and the pressure need to be increased in gradual steps. Holding the pressure at each step for a short time may allow for leak detection from the instrumentation system. All operators that were surveyed did not report any problem with their pipeline shut-in or start-up procedures.

## 5.3 Inspection and Leak Detection

Post-storm inspection is vital to access the damage to pipelines and risers, and detection of any leakage in the system. There are no industry-wide practices that are followed regarding post-storm inspection. Some operators routinely perform certain inspection activities and some perform inspection only if a leak is suspected. In the aftermath of Hurricane Andrew, MMS issued mandatory survey requirements for all pipelines in the corridor affected by the storm. Generally, visual detection of surface gas bubbles or oil from a ruptured line is done by a fly-over inspection or during a supply boat trip to the field. Diver inspection of risers and pipelines close to the platform are performed only if a leak or damage to the riser is evident. Side scan sonar and magnetometer surveys were performed by some companies after the storm to locate displaced lines. Use of ROVs was not mentioned by any operator and is not a common practice in the Gulf region. Ideally, running a ROV with a camera along the known pipeline route is the best way of determining the condition of the line so long as there is good visibility. Economic considerations make implementation of this procedure difficult. For lines shut-in at some pressure, line pressure readings can be used to judge if the leak is present. All of these methods mentioned are used to detect significant pipeline damage or leaks before the line is brought back into production.

After line start-up, a caliper pig may be used to detect any local damage along the pipeline. Several leak detection methods are available for detection of small leaks when the line is in operation. The most commonly used method is the mass balance method [15]. This method is based on the simple concept of conservation of mass. By metering the quantities of the fluid entering and leaving the pipeline and using pipeline parameters such as pressure and temperature to determine the amount of product in the line, the possibility of leak can be evaluated. The sensitivity of this method is dependent on the accuracy of the sensors and the instrumentation used. Detection of small sized leaks using this method requires monitoring of flow data over a long period. Several other methods such as acoustic emission, temperature profiling using fiber optic cables, negative pressure wave detection, etc., are at various stages of development. Reference [15] provides a good overview of these techniques. When developed, these techniques might be used to detect small or large leaks. Currently, cost and technical uncertainty in these methods prohibits their wide spread application to offshore pipelines.

# 6.0 ON-BOTTOM PIPELINE STABILITY RELIABILITY ANALYSIS

This section will start with a brief description of the general concepts in risk-based pipeline design and will be followed by discussions directly related to the reliability of offshore pipelines subjected to hurricane-induced wave motions. The primary focus of this effort was to develop and apply a time-varying reliability method to selected on-bottom instability example problems assuming storm conditions. It will be shown how the time-varying reliability method can provide useful information in analyzing and designing offshore pipelines.

## 6.1 Concepts in Risk-Based Pipeline Design

One of the difficulties in analyzing and designing offshore pipelines is in dealing with the various uncertainties involved. These uncertainties can be characterized as random variables and random processes. Examples of random variables are wind speed, material properties, hydrodynamic coefficients, seabed friction coefficients, wave-spectrum amplitude, and modeling uncertainties (e.g., soil and structure interaction, accuracy of applying the linear wave theory, etc.). Random processes include water level under calm conditions, sea wave heights, and underwater current.

To account for these uncertainties, there are currently two distinct approaches used in designing offshore pipelines. One is a deterministic approach and the other is a probabilistic approach. In the deterministic approach, either the maximum loads are calculated and applied to a static pipeline structural analysis or a wave time-history record is used to calculate time-dependent loads considering dynamic responses. In the probabilistic approach, the wave motion is treated as a random process. Traditionally, the random vibration approach is used where all calculations are done in the frequency domain. In both approaches, additional safety factors and bounds are applied to account for the random variables mentioned above. While the second approach is better from the reliability point of view, both approaches may lead to either over-design due to the compounding effects of safety factors or under-design if the extreme events are not fully accounted for.

Pipeline reliability-based design requires the identification of potential failure modes, the applied loads, the structure's geometry, material and other data, the target safety level, the suitable reliability analysis methods, and the design format.

The failure modes that have been previously considered include instability (excessive movements), yielding, buckling, rupture, fatigue, fracture, and corrosion. From the failure modes, limit states models need to be developed. The limit states involve the design parameters and structural responses (stresses, stress intensity factors, displacements, etc.) and are defined by analytical equations or complicated numerical models (e.g., finite element models).

The required data include the environmental conditions (wave, current, seabed condition), hydrodynamic coefficients, and pipe characteristics (materials, coatings, geometries). Based on the limit state functions, the probabilistic and deterministic input data (pressure loads, pipe properties, geometries, environmental considerations) need to be collected and synthesized using, for example, power spectrum and transfer functions, to develop probability models including random variables and random processes.

There are several ways to select target levels, for example, based on the safety level of the past and existing pipeline systems. A rational basis for selecting target safety levels is a cost-based risk analysis. Here, risk is defined as a function of the expected frequency of occurrence of an undesirable event and the expected damage. A simple model defines risk as the product of failure occurrence frequency and damage [Ref. 16]. Thus, quantifying probability of failure provides an avenue for quantifying risk. The consequences of a pipeline failure may include dollars lost, man-hours lost, environmental impacts, etc. If the primary damage is the loss of dollars, then risk is approximately equal to the dollar cost of failure. For illustration purposes, a simple cost model is defined as:

$$\text{Total Cost} = \text{Initial Cost} + \text{Maintenance Cost} + \text{Failure Cost}$$

in which the initial cost includes the design and manufacturing costs. It is reasonable to state that the objective of the pipeline reliability-based design is to minimize the expected life time cost. An optimal reliability target can ideally be selected to minimize the expected cost. However, establishing target safety levels must also consider intangible factors such as safety regulations, public concerns, and environmental impact.

The development of reliability methods has matured during the last two decades [Refs. 17-18]. Many reliability methods can be practically applied to complicated engineering problems. The application of these reliability methods to pipeline design have been proposed recently [Ref. 19]. Commonly used reliability-based design methods are based on the limit-state formulations and the design-point concept. In these methods, the design point, which is a point corresponding to the most likely failure condition, provides a rational basis to define partial safety factors and reliability-based design formats. A common approach uses this point, denoted as $x_i^*$, to define the partial coefficients (also known as partial safety factors) as $\gamma_i = x_i^*/x_i^o$, where $x_i^o$ are the nominal values. The partial safety factors are then used in the limit state equation to develop a safety checking format. To determine the optimal partial safety factors for a range of designs, a common approach is to set up a standard optimization problem as follows:

$$\textit{Minimize:}\quad S = \sum_{i=1}^{m} w_i \left(\log p_{fi} - \log p_{ft}^{*}\right)^2$$

where $w_i$ are the expected relative frequencies of the $m$ design situations, $p_{fi}$ are the failure probabilities, and $p_{ft}$ is the target failure probability.

## 6.2 Time-Variant Reliability Analysis

A major uncertainty in designing offshore structures is the wave forces which can best be modeled as random processes. Even without structural resistance degradation, the reliability of the structure is decreasing because there are more chances of encountering a high load as time increases. Thus, the time-varying sea states play a key role in reliability analysis. The traditional approach may be termed semi-probabilistic in the sense that characteristic values of the random processes are used in combination with spectrum analysis. For example, it is a common practice to use significant wave height (the expected value of the maximum 1/3 wave heights) based on a 100 year return period. While this method is simple relative to a full-probabilistic approach and provides some levels of confidence, the reliability cannot be quantified.

Time-invariant reliability methods have been well developed and documented [Ref. 17-18]. Some of these methods can be used to solve complicated problems involving large models using numerical methods such as the finite element method [Ref. 20]. On the other hand, time-variant reliability methods have been used less often but are useful tools for dealing with offshore pipeline structures under storm-induced wave forces. For this reason, the time-variant reliability method will be summarized with some details.

Time-varying reliability methods are methods for computing the probability of exceeding a failure barrier (or limit state) during a time period in which the reliability generally decreases as a function of time. When there is more than one random process, the analysis is commonly called vector-outcrossing. Even though there are several rules that have been proposed to address the load combination issue in a way that requires simpler analyses, the vector-outcrossing analysis method is more rigorous and provides more accurate solutions.

## 6.3 Vector-Outcrossing Reliability Analysis

The limit-state surface (e.g., the stability boundary) is defined as:

$$g(R, X(t)) = 0$$

where $R$ is a realization of the random variable vector $\boldsymbol{R}$, and $X(t)$ is a vector of Gaussian random processes (e.g., wave-induced loads). The structure will fail (i.e., not meeting the performance requirements) if the time-varying $g$-function passes the boundary and becomes negative. The probability of failure is the probability of $[g \le 0]$.

Given a vector of random variables $\boldsymbol{R}$ and a vector of stationary Gaussian stochastic processes, $\boldsymbol{X}(t)$, the probability of failure is defined as:

$$p_f = \int p_{f|R} \; f_R(r)\, dr = E[p_f \,|\, R]$$

where $f_R$ is the probability density function (PDF) of R and $p_{f|R}$ is the probability of failure conditioned on $R$. The conditional probability of failure can be computed using the mean outcrossing rate, $\nu$, based on the following approximate equation [Ref. 21]:

$$p_{f|R} = 1 - [1 - p_o] \exp\left[\frac{-\nu T}{1 - p_o}\right]$$

where $T$ is the time duration and $p_0$ is the conditional probability of failure at $T = 0$. An efficient and practical approach for computing $\nu$ is described in Appendix B. The expected (or average) number of crossings is the product of the mean outcrossing rate and the duration, i.e.,

$$N^{+} = \nu\, T$$

In some reliability analysis problems, such as the instability example described below, $N^{+}$ is an important measure of reliability.

During the design life of offshore pipelines, multiple hurricane storms are expected to occur. A Poisson distribution may be used to model the occurrences of hurricane events. The Poisson distribution is defined as:

$$p\,(n) = \frac{\lambda^{n}\, e^{-\lambda}}{n\,!}$$

where $\lambda$ is the average number of occurrences during the design life. If the duration of a single hurricane is $T$, then the duration of $n$ hurricanes during the design life will be $nT$. The total reliability can be computed as:

$$\text{Reliability} = \sum_{n=0}^{n=\infty} \text{Reliability } (n \text{ hurricanes})\; p\,(n)$$

in which Reliability ($n$ hurricanes) can be computed by the above vector-outcrossing method using $nT$ as the duration.

## 6.4 On-Bottom Stability Reliability Analysis Example

Submarine pipeline on-bottom stability has been the subject of research in recent years [Ref. 22-29]. Some of the pipeline breakouts during hurricanes can be attributed to excessive movements due to on-bottom instability phenomena. In the following, the instability problem will be analyzed using the vector-outcrossing method to compute the probability of instability. It should be noted that the instability is defined here as a condition where the pipe will be moved but will not necessarily cause a pipe failure. Several researchers have shown that, under certain conditions, the movement of a pipeline can cause embedment and increase the resistance force [Refs. 22-23]. Also, it has been shown that the lift force will reduce drastically if there is any flow under the pipe (e.g., if the pipe starts to lift off the soil, or in permeable soils), thus reducing the movement [Ref. 24].

The following analyses will focus on the computation of the expected number of crossings during a three-hour storm. The purpose of the example is to demonstrate how to formulate the problem to perform a time-variant reliability analysis, and draw useful conclusions.

### 6.4.1 *Limit-State Surface*

A pipeline on a flat sea bed is subjected to multiple time-varying forces that include a lift force $F_L$, a drag force $_F$, and an inertia force $F_I$. The instability criteria is

$$\mu (W_s - F_L) \leq F_D + F_I$$

where $W_s$ is the submerged weight and $\mu$ is the resistance coefficient. The only resistance against the lateral movement is the frictional force between the pipeline and the seabed. Resistance can be increased by increasing the submerged weight (e.g., by increasing the concrete coating) and the friction coefficient (e.g., by trenching). The limit-state surface can be formulated as:

$$g(\boldsymbol{R}, \boldsymbol{X}(t)) = \mu (W_s - F_L) - (F_D + F_I) = 0$$

where $\boldsymbol{R}$ is a vector of random variables and $\boldsymbol{X}$ is a vector of random processes.

### 6.4.2 *Pipeline Design Parameters*

The following representative data are assumed for this example:

Pipe outside diameter, $D$ = 0.324 m (12.75 in)
Pipe wall thickness, $t$ = 0.00953 m (0.375 in)
Corrosion coating thickness, $t_{cor}$ = 0.004 m (0.1563 in)
Pipe steel density, $\rho_{st}$ = 7850 kg/m$^3$ (490 lb/ft3 (pcf))
Corrosion coating density, $\rho_{cor}$ = 1842 kg/m$^3$ (115 pcf)
Product density, $\rho_P$ = 832.9 kg/m$^3$ (52 pcf) (oil)
Seawater density, $\rho_W$ = 1025 kg/m$^3$ (64 pcf)
Concrete coating density, $\rho_{con}$ = 2240 kg/m$^3$ (140 pcf)
Concrete coating thickness, $t_{con}$ - *to be designed*

From the above data, the submerged weight can be computed as:

$$W_s = 0.25\,\pi\, g \{ [(D-2t)^2]\,\rho_p + [D^2 - (D-2t)^2]\,\rho_{st} + [(D+2t_{cor})^2 - D^2]\,\rho_{cor}$$
$$+ [(D+2t_{cor}+2t_{con})^2 - (D+2t_{cor})^2]\,\rho_{con} - [(D+2t_{cor}+2t_{con})^2]\,\rho_w \}$$

The objective of the design is to calculate the required concrete coating thickness that would provide sufficient submerged weight.

### *6.4.3 Hydrodynamics Forces*

The drag, lift, and inertia forces are defined based on Morrison's equation:

$$F_D = \frac{1}{2} \rho_W D_e C_D \mid v_s + v_c \mid (v_s + v_c)$$

$$F_L = \frac{1}{2} \rho_W D_e C_L (v_s + v_c)^2$$

$$F_I = \frac{\pi D_e^2}{4} \rho_W C_M a$$

where $v$ is the particle horizontal velocity due to storm, $v_c$ is the current velocity, $D_e$ is the effective outside diameter of the pipe, $C_D$ is the drag coefficient and $C_M$ is the inertia coefficients, and $C_L$ is the lift coefficient.

The coefficients are subject to considerable uncertainties [Ref. 19] and will be treated as normal random variables. For the example problem, a coefficient of variation (standard deviation/mean) of 20% is assumed for all the three coefficients. The means and standard deviations are shown in the following.

$C_D$ = Normal ~ (0.7, 0.14)
$C_L$ = Normal ~ (0.9, 0.18)
$C_M$ = Normal ~ (3.29, 0.66)

The following data will be assumed to be deterministic even though they potentially can also be treated as random variables.

Water depths = 30.48 m (100 ft), 15.24 m (50 ft)
Storm current on seabed = 0.3 m/s (1 ft/s)
Soil friction = 0.7 (sand)

### *6.4.4 Random Wave Forces*

Define the distance from the sea bottom, where the pipeline is located, to the sea surface as $d$. The sea surface elevation above still water level may be expressed as

$$\eta(t) = a \cos(kx - \omega t) = a \cos \theta$$

where $a$ is the wave amplitude, $k$ is the wave number and $\omega$ is the wave frequency (rad/s).

For this example, the following sea wave data are assumed:

Significant wave height ($H_s$): 9.653 m (31.67 ft); 7.111 m (23.33 ft)
Wave spectrum: Pierson-Moskowitz spectrum
Storm duration: 3 hours

The Pierson-Moskowitz spectrum can be expressed as [Ref. 30]:

$$S(f) = \frac{A}{f^5} \exp\left( - \frac{B}{f^4} \right)$$

where $A$ is a constant and $B$ depends on the wind velocity $U$ as follows:

$$A = 0.0081 \frac{g^2}{(2\pi U)^4}$$

$$B = 0.74 \frac{g}{(2\pi U)^4}$$

where $g$ = 9.81 m/sec$^2$ and $U$ is wind speed in m/s. The P-M spectrum is suitable for the fully-developed seas.

By integrating the spectrum, it can be shown that the zeroth-order moment, or the variance, can be computed from $A$ and $B$ as follows:

$$m_0 = \sigma_\eta^2 = \frac{A}{4B}$$

Also,

$$H_s = 4\,\sigma_\eta$$

Given $H_s$, the constants $A$ and $B$, as well as the wind velocity, $U$, can be computed. For example, for $H_s$ = 9.653 m, $U$ = 21.28 m/s and for $H_s$ = 7.111 $m$, $U$ = 18.26 m/s.

The limit-state surface involves the water particle velocity and acceleration random processes. To obtain these from the sea wave spectrum, $S_\eta(f)$, the transfer functions from the sea surface to the bottom are required. From the linear wave theory it can be shown that:

$$S_v(f) = |H_v(f)|^2 S_\eta(f) = \frac{4\pi^2 f^2}{\sinh^2(kd)} S_\eta(f)$$

$$S_a(f) = |H_a(f)|^2 S_\eta(f) = \frac{16\pi^4 f^4}{\sinh^2(kd)} S_\eta(f)$$

in which $k$ can be computed from the following equation:

$$kd \tanh(kd) = \frac{4\pi^2 f^2}{g}$$

For each $f$, $kd$ can be found by an iterative procedure or by a graph. By integrating the velocity and acceleration spectrum, the standard deviations are:

For $H_s = 9.653$ m ($d = 30.48$ m), $\sigma_v = 1.052$ m/s, $\sigma_a = 0.4767$ m/s$^2$

For $H_s = 7.111$ m ($d = 15.24$ m), $\sigma_v = 1.213$ m/s, $\sigma_a = 0.6709$ m/s$^2$

Notice that the significant wave height for the second case is lower, but its standard deviations are higher because of a smaller $d$.

For time-variant reliability analysis, the derivative of the acceleration process, $\dot{a}(t)$, is also needed. From the relation $S_{\dot{a}} = 4\pi^2 f^2 S_a$, the following standard deviations were computed.

For $H_s = 9.653$ m (d = 30.48 m), $\sigma_{\dot{a}} = 0.2414$ m/s$^3$

For $H_s = 7.111$ m (d = 15.24 m), $\sigma_{\dot{a}} = 0.4250$ m/s$^3$

Because the random processes involved are statistically independent [Ref. 30], the covariance matrices, which are required to compute mean outcrossing rate (see Appendix B) can now be defined as follows:

$$C_{va} = \begin{bmatrix} \sigma_v^2 & 0 \\ 0 & \sigma_a^2 \end{bmatrix}$$

$$C_{vd} = \begin{bmatrix} \sigma_a^2 & 0 \\ 0 & \sigma_d^2 \end{bmatrix}$$

### *6.4.5 Analysis Results*

Two reference concrete coating designs for the above two cases were created first to provide a basis for comparison. The reference designs were computed based on a simplified static analysis procedure [Ref. 11]. In this procedure, the velocity is defined as twice the standard deviation times a reduction factor. In the example, a reduction factor of 0.5 was used representing a 30-degree angle between the wave direction and the longitudinal direction of the pipelines. In each case, the phase angle between the velocity and the acceleration waves was selected to maximize the required submerged weight. The calculated concrete thicknesses were:

For $H_s = 9.653$ m (d = 30.48 m), $t_{con} = 2.31$ cm

For $H_s = 7.111$ m (d = 15.24 m), $t_{con} = 3.88$ cm

Based on the above thicknesses, several designs were analyzed and the results are listed in Table 15. The average numbers of zero crossings, denoted as $N_o^+$, are computed based on the expected zero crossing rates. Thus, during the three-hour storm, there are approximately 978 and 1140 waves, respectively, for the two wave spectrum.

**Table 15. Computed Expected Number of Crossings**

| Run | d (m) | Hs (m) | t (cm) | $N_o^+$ | RVs | $p_f$ | $\nu$ | $N^*$ | Remarks |
|---|---|---|---|---|---|---|---|---|---|
| 0 | 30.48 | 9.651 | 1.42 | 1140 | No | 0.01 | 0.005 | 56 | Inertia effect neglected |
| 1 | 30.48 | 9.651 | 1.42 | 1140 | Yes | 0.01 | 0.006 | 67 | t= 1.42 cm based on static design |
| 2 | 30.48 | 9.651 | 1.42 | 1140 | No | 0.01 | 0.006 | 65 | |
| 3 | 30.48 | 9.651 | 2.84 | 1140 | No | 0.01 | 0.005 | 53 | |
| 4 | 30.48 | 9.651 | 4.26 | 1140 | No | 0.01 | 0.003 | 31 | |
| 5 | 30.48 | 9.651 | 4.26 | 1140 | Yes | 0.01 | 0.003 | 34 | |
| 6 | 30.48 | 9.651 | 7.11 | 1140 | No | 0.01 | 0.005 | 12 | |
| 7 | 30.48 | 9.651 | 1.42 | 1140 | No | 0.01 | 0 | 5 | Opposite current direction |
| 8 | 16.24 | 7.111 | 3.33 | 978 | Yes | 0.03 | 0.011 | 120 | t= 3.3 cm based on static design |
| 9 | 16.24 | 7.111 | 3.33 | 978 | No | 0.02 | 0.011 | 118 | |
| 10 | 16.24 | 7.111 | 6.66 | 978 | No | 0.02 | 0.005 | 50 | |
| 11 | 16.24 | 7.111 | 9.99 | 978 | No | 0 | 0.002 | 22 | |
| 12 | 16.24 | 7.111 | 9.99 | 978 | Yes | 0 | 0.002 | 24 | |

To show the effect of increasing the concrete coating thicknesses, the expected numbers of crossings for several thicknesses are plotted in Figure 16.

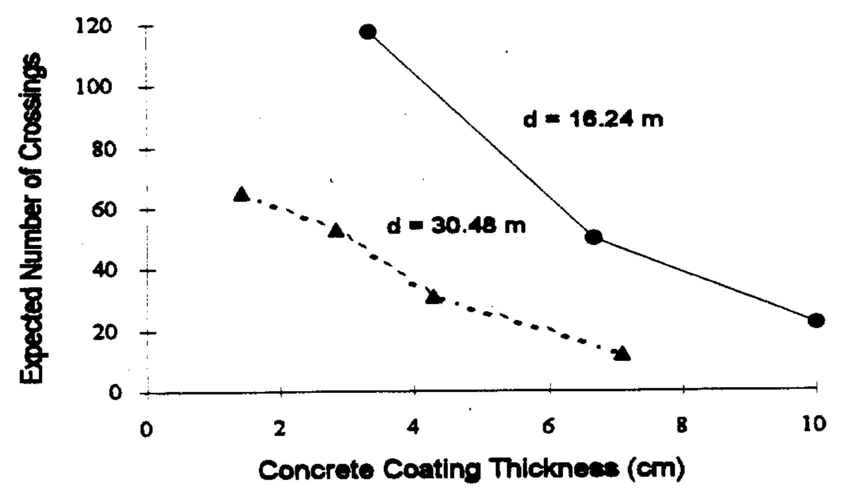



**Figure 16. Expected Number of Crossings Versus Concrete Coating Thickness for Two Cases.**

## 6.5 Summary and Discussions

1. For pipeline designed based on a single wave with the amplitude equals to two standard deviations of the wave process, the results show that the stability conditions will be violated many times during the storm. Increasing the concrete coating thickness will decrease the expected number of crossings, but within reasonable thickness limits it is impractical to reduce the expected number of crossing to be sufficiently less than one for high reliability. On the other hand, under a dynamic loading process, violating the stability criteria does not constitute a structural failure (i.e., breakout). Rather, it implies that the pipeline will be moved and in some cases it may cause embedment (not included in the current model), thereby increase the resistance. Therefore, using the current two-dimensional stability model to define failure is impractical. A failure criteria based on strain or displacement limits is needed for reliability design. A three-dimensional dynamic model might be needed to introduce stiffness.

2. Knowing the expected number of crossings does not provide direct information to quantify the actual reliability because the instability limit state is not a failure limit state. However, it seems reasonable to assume that the more crossings a pipeline experiences, the more likely it will fail because of the increasing chances in encountering an extreme wave that might cause excessive pipeline movements. It would be useful to apply the time-variant reliability analysis method to those pipelines that survived Hurricane Andrew to find out how many crossings

can be tolerated by the pipelines. This information would be useful for developing a reliability-based design criteria.

3. The results show that the assumed random variables (RVs) do not have significant impacts to the mean crossing rates (see runs 1, 5, 8, 12). This may be because the drag force and the left force are both proportioned to the square of the particle velocity. In other words, the velocity is the dominant parameter.

4. The inertia effect due to wave acceleration is relatively insignificant compared with the velocity effect (see runs 0 and 1).

5. In other runs not listed in Table 15, it was found that it is possible to reach the instability condition along the direction that opposes the current, but the expected number of crossings are significantly smaller than the other direction. This means that the crossings are more likely to occur in the current direction. However, it can be expected that for smaller current speed, the pipelines will be moved in both directions.

## 7.0 CONCLUSIONS & RECOMMENDATIONS

This section summarizes SwRI's conclusions based on the results of the study. Recommendations are also made to reduce damage to pipelines during future hurricanes.

### 7.1 Conclusions

Hurricane Andrew resulted in damage to about 485 pipeline segments. More than half of these had the associated platform and the satellite jacket structures damaged. Even after excluding these segments, damage to pipelines has been excessive. For example, there were only 97 storm related pipeline failures during the 24-year pre-Andrew period of 1967 to 1991. In contrast, Andrew resulted in damage to 103 riser sections and 44 pipeline sections on the seabed. There were 18 pipeline failures due to damage from anchors or anchor lines, or direct impact with mobile offshore drilling units (MODU) that drifted during the storm. Ten pipeline failures were attributed to mud slides. About 28 pipe small sized pipe segments (2"-6" OD) lost anodes. For nine medium sized (8"-16" OD) and large sized (18"-36" OD) lines segments, sand bags or concrete cover mats had to be replaced. The large number of pipelines and flow lines existing in the corridor affected by Andrew may have caused this large number of failures.

About 87% of the pipelines damaged were of small size (2"-6" OD). Most of the failures occurred in water depths of less than 70 feet. The largest number of failures were among the 4" size lines which seem to have the largest occurrence in the storm affected area. Although the failure distribution among the three pipe sizes seems to be approximately in proportion to their population in the area affected by Andrew, the mode of failure for each pipe size group was distinctly different. Among the small size lines, most of the damage occurred in the riser section or at the riser-to-pipeline subsea tie-in. A significant number of small size lines failed due to excessive pipeline movement away from the platform. There was no significant damage to large size lines except for the loss of cover in some cases. Among the medium and large size lines, failures occurred most frequently in the pipeline section on the seabed. The majority of failed lines were used to transport oil or were service flowlines to satellite wells.

Mud slide related failures occurred mostly among the medium size lines (8"-16"). The break-away connectors used on lines impacted by mud slides worked satisfactorily in only half of the cases. In two cases, more than 1000 feet of line had to be replaced and in three cases the associated risers had to be repaired. An improvement in the performance reliability of break-away connectors is desirable.

Anchor damage from drifting MODUs occurred mostly among the small size lines. Only two 8" risers were damaged from direct impact (from a tilted jack-up rig). All anode losses on pipelines were among small size lines. Most of these lines belonged to only one operator.

There was only one major incident of oil spillage which resulted in a release of about 2000 bbl. This was caused by the rupture of a 20" oil line which, in turn, was caused by anchor impact from a drifting rig. There were other small leaks which resulted in release of an additional 500 bbl. The operators did not record the spills caused by pipelines which pulled apart. Oil spillage from pipelines damaged during the 24 years prior to Andrew was relatively low. There were only two spills with releases of 250 and 80 bbl, respectively, during this period. Another 11 storm related failures resulted in spills of less than 10-20 bbl. Overall pollution from pipelines damaged during all storms has been low and does not appear to be a major concern.

Pipe age did not appear to have a significant influence on storm related failures compared with the influence of pipe size. This implies that several lines failed during Hurricane Andrew even though they were designed to the 100-year storm criteria. There was a relatively small number of lines damaged which were suspected to have been designed to the 25-year storm criteria.

Analysis of MMS pipeline failure data prior to Andrew showed trends consistent with those for Andrew. For storm related failures occurring during 1967-91, the majority of failures were among small sized lines and in the riser section. The mud slide related failures during this period were mostly on medium size lines. Most of the lines damaged due to the storm were transporting oil.

DOT and the MMS regulations require that all pipelines and flow lines installed in water depths of less than 200 feet be buried at least three feet below the seabed. Normally, a pipeline buried below the seabed is protected from the hydrodynamic loading generated during severe storms. Since almost all of the damaged lines were within this water depth, the question arises as to why so many lines failed? Two possibilities are suggested. The first possibility is that the majority of these lines may not have been buried below the seabed when the storm arrived. Since there are no mandatory requirements for inspecting burial depth, and since most operators do not seem have a well defined policy regarding regular periodic pipeline inspection, it is difficult to determine actual burial depth at the time of Andrew's arrival. The second possibility is that many of these lines, especially small sized ones, may have been installed for self-burial in soft sediments. During the storm, the transportation of sediments may have caused the lines to move laterally. Calculation of in-place stability for lines installed for self-burial is difficult. Due to the unavailability of detailed, site-specific data, the exact causes of pipeline failures could not be determined.

The principal aspects of designing pipelines for safety against extreme storm loading were reviewed. Current design procedures and code requirements were also discussed. The major uncertainty in these procedures exists in regard to the design of small sized lines in under-consolidated soils for protection during severe storms. Although riser failures form a major portion of the total damage to pipelines during storms, the design methodology for risers is well established. Inadequate design analysis of small sized risers and improper maintenance of risers and riser support clamps may have contributed to the failures experienced.

The overall procedures currently being followed by operators regarding pipeline shut-in prior to a storm's arrival, and for post-storm inspection and pipeline startup, seem to have worked satisfactorily. Pipeline isolation devices and control systems generally worked well. Consequently, the study did not result in any recommendations for significant pollution mitigation measures. Leaving the oil and gas lines shut-in with some nominal pressure will allow for their post-storm rupture/leakage detection from the line pressure reading. This will prevent the inadvertent startup of lines already ruptured and will avoid subsequent spillage that could occur.

A survey of the operators was performed to determine their experience with Hurricane Andrew. The survey resulted in information on several issues such as: pipeline shut-in procedures, post-storm inspection methods, design criteria, performance of mechanical connectors and break-away joints, probable cause of failures, etc.

A reliability based pipeline design model was developed for on-bottom stability during a severe storm. The model can be used for assessing the risk of failure under a combination of influencing random factors. The sensitivity of pipeline safety to variations in key parameters has been determined using a sample problem.

## 7.2 Recommendations

1. Efforts should be made to improve the safety level of new and existing platforms and jackets and their ability to withstand the 100-year storm conditions. This will have the obvious benefit of reducing pipeline failures caused by damage to associated platform structures.

2. Efforts should be made to improve anchoring systems and the station keeping ability of mobile rigs left unattended during a storm. When possible, they should be moved away from the likely path of a storm. This will reduce the risk of damage to pipelines and other structures from drifting vessels.

3. Improved methods should be developed for designing and protecting small sized lines in shallow water depths. When these lines are installed in consolidated soils, trenching and burying them three feet or more below the seabed will be adequate to protect them during storms. The stability of lines installed in wide angled trenches needs to be investigated. The burial depth should be periodically verified by inspection.

4. For small sized lines installed for self-burial in soft sediments, improved methods are needed to verify the stability of the line under storm conditions. In the meantime, it is recommended that the small size lines be piggy-backed with other larger diameter lines. When this is not feasible, the use of other design options such flexible jumper hoses at the pipeline-to-riser connection may be considered in water depths of less than 100 feet. These should have adequate slack designed into them.

5. The riser, supporting clamps and the section of pipeline adjacent to the platform should be carefully analyzed to insure their integrity under 100-year storm conditions. This analysis should include the influence of platform motion during storms and the flexibility of platform bracing, when the clamps are attached to platform members.

6. Periodic inspection and maintenance of risers and the supporting clamps are important to ensure their satisfactory performance during storm conditions. Missing clamps or loose clamp bolts can result in significantly different stresses in the riser from the design stress level.

The recommendations made in items 1 and 2 will evolve through the results of other studies sponsored by the MMS. The industry is encouraged to consider the remaining four items.

## 8.0 REFERENCES


1. Daniels, G. R., "Hurricane Andrew's Impact on Natural Gas and Oil Facilities on the Outer Continental Shelf," Interim Report as of November 1993, Minerals Management Service, Herndon, Report No. MMS 94-0031.

2. Mandke, J. S., "Corrosion Causes Most Pipeline Failures in Gulf of Mexico," Oil & Gas Journal, October 29, 1990.

3. Minerals Management Service, "Pipeline Leaks and Breaks," New Orleans, LA.

4. API RP 2 A, "Recommended Practice for Planning, Designing, and Constructing Fixed Offshore Platforms - Working Stress Design," 20th Edition, July 1, 1993.

5. Williamson, W., "Overview of OCS Pipeline Damage Occurring During Hurricane Andrew," Presented at International Workshop on Damage to Underwater Pipelines, New Orleans, February 22-24, 1995.

6. Mandke, J. S. and J. R. Shaw, "Design of Submarine Pipeline Riser Requires Special Analysis," Pipeline & Gas Journal, June 1978.

7. DnV 1976, "Rules for the Design, Construction and Inspection of Submarine Pipelines and Pipeline Risers."

8. DnV 1981, "Rules for Submarine Pipeline Systems."

9. ASME B31.8, "Gas Transmission and Distribution Piping Systems," 1992 Edition.

10. Allen, D. W., et al., "Submarine Pipeline On-Bottom Stability: Recent AGA Research," Offshore Technology Conference, Houston, OTC 6055, 1989.

11. RPE 305, "On-Bottom Stability Design of Submarine Pipelines," Veritec, 1988.

12. Nataraja, M. S. and H. S. Gill, "Ocean Wave-Induced Liquefaction Analysis," ASCE Journal of Geotechnical Engineering, Vol. 109, No. 4, April 1983.

13. Bryndum, M., et al., "Pipeline In-Place Stability on Erodable Seabeds," International Conference on Offshore Mechanics and Arctic Engineering, Volume V, Pipeline Technology, 1993.

14. Bruschi, R., et al., "Self-Lowering of a Pipeline on Erodable Seabed in Shallow Waters: Predictions and First Year Experience," International Conference on Offshore Mechanics and Arctic Engineering, Volume V, Pipeline Technology, 1993.

15. Turner, N. C., "Hardware and Software Techniques for Pipeline Integrity and Leak Detection Monitoring," Offshore Europe Conference, Aberdeen, September 1991.

16. McCormick, N. J., Reliability and Risk Analysis, Academic Press, Inc., San Diego, 1981.

17. Madsen, H. O., S. Krenk, and N. C. Lind, Methods of Structural Safety, Prentice-Hall, Englewood Cliffs, New Jersey, 1986.

18. Thoft-Christensen, P. and M. J. Baker, Structural Reliability Theory and Its Applications, Springer-Verlag, New York, 1982.

19. Sotberg, T. and B. J. Leira, "Reliability-Based Pipeline Design and Code Calibration," Offshore Mechanics and Arctic Engineering, Vol. V, ASME, New York, pp. 351-363, 1994.

20. Wu, Y.-T., H. R. Millwater, and T. A. Cruse, "An Advanced Probabilistic Structural Analysis Method for Implicit Performance Functions," AIAA Journal, Vol. 28, No. 9, pp. 1663-1669, September 1990.

21. Ditlevsen, O., "Gaussian Outcrossings from Safe Convex Polyhedrons," Journal of Engineering Mechanics, Vol. 109, No. 1, pp. 127-148, February 1983.

22. Allen, D. W., W. F. Lammert, J. R. Hale, and V. Jacobsen, "Submarine Pipeline On-Bottom Stability: Recent AGA Research," OTC Paper 6055, Proceedings of the 21st Annual Offshore Technology Conference, Houston, Texas, May 1-4, 1989.

23. Jacobsen, V., M. B. Bryndum, and D. T. Tsahalis, "Prediction of Irregular Wave Forces on Submarine Pipelines," Proceedings of the Seventh International Conference on Offshore Mechanics and Arctic Engineering, Houston, Texas, February 7-12, 1988.

24. Hale, J. R., W. F. Lammert, and V. Jacobson, "Improved Basis for Static Stability Analysis and Design of Marine Pipelines," OTC Paper 6059, Proceedings of the 21st Annual Offshore Technology Conference, Houston, Texas, May 1-4, 1989.

25. Jacobson, V., M. B. Bryndum, and C. Bonde, "Fluid Loads on Pipelines: Sheltered or Sliding," OTC Paper 6056, Proceedings of the 21st Annual Offshore Technology Conference, Houston, Texas, May 1-4, 1989.

26. Brennodden, H., J. T. Lieng, and T. Sotberg, "An Energy-Based Pipe-Soil Interaction Model," OTC Paper 6057, Proceedings of the 21st Annual Offshore Technology Conference, Houston, Texas, May 1-4, 1989.

27. Lammert, W. F., J. R. Hale, and V. Jacobsen, "Dynamic Response of Submarine Pipelines Exposed to Combined Wave and Current Action," OTC Paper 6058, Proceedings of the 21st Annual Offshore Technology Conference, Houston, Texas, May 1-4, 1989.

28. Chao, J. C. and K. F. Lambrakos, "Hydrodynamic Force Characteristics for Submarine Pipelines," OTC Paper 6060, Proceedings of the 21st Annual Offshore Technology Conference, Houston, Texas, May 1-4, 1989.

29. Zhao, Y. and K. Anastasiou, "Bottom Friction Effects in the Combined Flow Field of Random Waves and Currents," *Coastal Engineering*, 19, pp. 223-243, 1993.

30. Sarpkaya, T. and M. Isaacson, Mechanics of Wave Forces on Offshore Structures, Van Nostrand Reinhold Company, Dallas, Texas, 1981.

31. Recommended Practice, "On-Bottom Stability Design of Submarine Pipelines, Volume E: Pipelines and Risers, Group E 300: Strength and In-Place Stability of Pipelines," Veritas Offshore Technology and Services A/S, October 1988.

# APPENDIX A

## Survey Questionnaire

# Survey of Pipeline Damage due to Hurricane Andrew

Company: ______________________________

Survey Completed by: ______________________________

Address: ______________________________

Phone No.: ______________________________

1. Enclosed data sheet(s) shows the pipelines and/or pipeline risers operated by your company that are recorded as "damaged" (required repair) by the Minerals Management Service (MMS). Is this data correct?

   ________ Yes

   ________ No (Please explain)

   ______________________________________________

   ______________________________________________

   ______________________________________________

2. Design wave and current used on older pipelines (pipelines installed before 1970).

   Wave Height ____________________

   Period ____________________

   Current ____________________

3. Design wave and current used on new pipelines (pipelines installed in or after 1970).

   Wave Height ____________________

   Period ____________________

   Current ____________________

4. Procedures generally followed to shut off the pipelines (including intrafield lines) prior to hurricane arrival. If you use different procedures for oil, gas, or multi-phase lines, please explain. (Describe if the lines are left full pressure, reduced pressure, or empty.)

   ______________________________________________

   ______________________________________________

   ______________________________________________

   ______________________________________________

   ______________________________________________

   ______________________________________________

   ______________________________________________

   ______________________________________________

   ______________________________________________

5. How do you assess the damage to pipelines prior to returning the lines to service when the damage is not visible?

(a) Fly-Over Inspection ____________________
(b) ROV Inspection ____________________
(c) Diver Inspection ____________________
(d) Inspect only if leak is detected ____________________
(e) Other ____________________

Comment(s): ____________________

6. A very large portion of the pipeline risers damaged during Hurricane Andrew were of small size (2" to 6" diameter). Do you have any opinion regarding the extensive damage to small size pipeline risers?

7. Can you briefly summarize your company's experience regarding mechanical connectors, break-away safety joints, flexible jumper hoses, etc.? Did these devices help in saving the riser or the pipeline on the seabed from damage?

8. Briefly summarize your company's experience regarding buried pipelines that were in the path of the hurricane. Did the pipelines remain in the trench as-built, or was there a loss of backfill, pipe movement out of the trench, etc.?

9. Compared to previous hurricanes, Hurricane Andrew resulted in damage to a very large number of pipelines and risers. This statement is valid even after excluding the damage to pipelines and risers that were associated with failed platforms. Do you have any opinion regarding why such a large number of pipelines failed during Hurricane Andrew?

10. Can you attribute any unique features with pipelines and risers that were in the path of Hurricane Andrew, but did not get damaged?

11. We would like to analyze some of the pipelines and risers that failed, and some of those that survived Hurricane Andrew, when the associated platform was not damaged. This will assist us in determining the cause of failure. Can you provide engineering data on two or three pipelines for these analyses? If so, please state the line sizes.

Please mail your response to:

Warren Williamson (MS 5232)
Minerals Management Service
1201 Elmwood Park Boulevard
New Orleans, Louisiana 70123-2394

# APPENDIX B

## Vector-Outcrossing Reliability Analysis

# VECTOR-OUTCROSSING RELIABILITY ANALYSIS

There are a number of methods that have been proposed to treat time-variant structural reliability problems. These include the simulation methods [Refs. 16-17] and the approximate methods [Refs. 18-20]. The method used for the on-bottom instability reliability analyses in the main text is described here.

## Probability of Failure

Given a vector of random variables $\boldsymbol{R}$ and a vector of stationary Gaussian stochastic processes, $\boldsymbol{X}(t)$, the probability of failure is defined as:

$$P_f = \int P_{f|R} f_R(r)\, dr = E\,[p_f \mid R]$$

where $f_R$ is the probability density function (PDF) of R, $p_{f|R}$ is the conditional probability of failure, and $E\,[.]$ is the expected value.

The conditional probability of failure can be estimated using the mean outcrossing rate, $\nu$, based on the following approximate equation [Ref. 18]:

$$p_{f|R} = 1 - [\,1 - p_o\,]\, \exp\left[\frac{-\nu T}{1 - p_o}\right]$$

where $T$ is the time duration and $p_o$ is the conditional probability of failure at $T = 0$.

## Mean Outcrossing Rate

The mean outcrossing rate can, in general, be computed by simulating random processes. However, it may become very computation intensive because the simulation needs to be performed repeatedly for a large number of times for each sampled $\boldsymbol{R}$ vector. A more efficient and practical approach is to approximate the boundary of the safe-failure sets by a linear boundary at an approximate point. It has been suggested that this point can be determined based on the first-order reliability method (FORM) [Refs. 18-19].

Following the notations commonly used in the literature, the limit-state surface (i.e., the boundary or the barrier) is defined as:

$$g\,(R, \boldsymbol{X}(t)) = 0$$

where $R$ is a realization of the random variables and $X(t)$ is a vector of Gaussian random process (e.g., wave-induced loads). The structure will fail or the performance will not meet the requirement if the time-varying $g$-function passes the boundary and becomes negative.

In the FORM analysis, the standardized normal variables (i = 1, n) are defined as:

$$u_i = \frac{X_i - \mu_i}{\sigma_i}$$

where $\mu_i$ and $\sigma_i$ are the expected value and the standard deviation, respectively, of the $X_i$ Gaussian process. Using the above equation, the original limit-state can be formulated in the u-space, i.e.,

$$g(\boldsymbol{u} \mid \boldsymbol{r}) = 0$$

where $\boldsymbol{r}$ is a realization of $\boldsymbol{R}$.

The approximation point is defined as the point on the boundary (i.e., limit state) that is closest to the origin. From this point, the mean out-crossing rate is approximated as:

$$\nu \approx \frac{1}{2\pi}\left(\alpha^T C_{\dot{u}\dot{u}}\, \alpha\right)^{1/2} \exp\left(-\frac{\beta^2}{2}\right)$$

where $\beta$ is the minimum distance to the boundary, $\alpha$ is the unit normal vector of the boundary, and $C_{\dot{u}\dot{u}}$ is a co-variance matrix computed from

$$C_{\dot{u}\dot{u}} = L^{-1} C_{\dot{X}\dot{X}} (L^{-1})^T$$

where $C_{\dot{X}\dot{X}}$ is the covariance matrix of the time derivative processes $\dot{X}(t)$ and $L^{-1}$ is the inverse of the lower triangular Cholesky factorization of $C_{XX}$ such that

$$L L^T = C_{XX}$$

Thus, the basic probabilistic data requirements include the expected values of $X$ and the covariance matrices $C_{XX}$ and $C_{\dot{X}\dot{X}}$.

In the literature, a nested-FORM approach has been proposed to compute the total probability of failure [Ref. 20]. The approach basically requires solving two nested optimization problems. Here, we propose to use a sampling method to compute the above expected value, $E\,[\,p_f \mid R\,]$. In the example problems, the Latin Hypercube sampling (LHS) method [Ref. 21] are used. The reasons for using this approach are: (1) The nested approach increases the chances of encountering numerical difficulties, (2) Computing expected value generally does not require a large number of random samples, and (3) The LHS method is generally more efficient than the standard Monte Carlo method for computing expected values.

The above discussion assumes a single limit state. For multiple limit states, a bounding approach [Ref. 18] or simulation approaches using strips or directional simulation [Refs. 16, 17] have been proposed.

**References**


1. Chan, H. Y. and R. E. Melchers, "A Simulation Method for Time-Dependent Structural Reliability," Computers and Structures, Vol. 49, No. 6, pp. 989-996, 1993.

2. Ditlevsen, O., P. Bjerager, R. Olesen, and A. M. Hasofer,"Directional Simulation in Gaussian Processes," Probabilistic Engineering Mechanics, Vol. 3, No. 4, pp. 207-217, 1988.

3. Ditlevsen, O., "Gaussian Outcrossings from Safe Convex Polyhedrons," Journal of Engineering Mechanics, Vol. 109, No. 1, pp. 127-148, February 1983.

4. Wen, Y. K. and H.-C. Chen, "On Fast Integration for Time Variant Structural Reliability," Probabilistic Engineering Mechanics, Vol. 2, No. 3, pp.156-162, 1987.

5. Madsen, H. O. and L. Tvedt, "Methods for Time-Dependent Reliability and Sensitivity Analysis," Journal of Engineering Mechanics, Vol. 116, No. 10, pp. 2118-2135, October 1990.

6. McKay, M. D., W. J. Conover, and R. J. Beckman, "A Comparison of Three Methods for Selecting Values of Input Variables in Analysis of Output from a Computer Code," Technometrics, **21**(2), pp. 239-245, 1979.